DISTANCE AND OVER CURRENT RELAYS : RELAY SETTING AND COORDINATION

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CERTIFICATE

Certified that the work entitled ''Distance and Overcurrent Relays : Relay Setting and Coordination'' which is being submitted by Mr. Vijay Pratap Singh in partial fulfilment of the award of the degree of Master of Technology, has been carried out under my supervision and guidance. The matter presented in this thesis dissertation has not been submitted elsewhere for a degree.

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ABSTRACT

The basic role of the transmission line protection scheme is to sense faults on the lines and rapidly isolate them by opening all incoming current paths. Thus a need arises for highly sensitive, selective, reliable and fast operating protective scheme. The protective relays, an important component of protection scheme, function as a sensing device. The protective relays using solid state components have numerous advantages over electromagnetic and electronic relays. However, the digital relaying scheme, because of its flexibility and self-checking characteristic, has a bright future especially for the protection of EHV/UHV transmission lines.

In this thesis, distance relays and overcurrent relays setting and co-ordination have been discussed. A number of software packages have been developed to optimise the number of fault studies to be carried out for relay settings at different locations. Here, we present suitable algorithms for generating the required input datas for the purpose of relay settings and coordination. Finally, the thesis concludes with a discussion on the results of a case study of Chukha Transmission System.

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CHAPTER-1

INTRODUCTION

The basic role of the transmission line protection system is to sense faults on line or at buses and to rapidly isolate these faults by opening all incoming current paths. This sensing and switching must occur as fast as possible, to minimise damages. However, protection scheme should be very selective so that only the faulted element is removed. This has led to the practice of providing primary protection with back-up which should function only when primary fails. Primary protection is designed for high speed and minimum network disruption while the back-up system operates slowly and generally affects larger portion of network. The proper coordination of primary & back-up relays for all possible faults is the main criteria to be satisfied to avoid false tripping and relay maloperation.

Co-ordination among relays requires the knowledge of type of protection schemes and operating time. The operating time of primary and back-up relays depends upon the type of relays used and their characteristics. Each line has a variety of relays at the buses. Typically there will be both ground and phase relays; first protects against ground faults and second against phase faults. The relaying scheme may use overcurrent relays or distance relays,

The overcurrent relay usually consists of an instantaneous unit and a time delayed unit, in which the time delay depends upon the magnitude of current i.e. distance to fault. The distance relay usually consists of an instantaneous unit (zone-1) and usually two time delay units (zone-2 and zone-3). Generally zone-3 unit is used to start the carrier

One of the main topic of concern to the protection engineers is the proper coordination behaviour of different relay units so as to avoid relay maloperation. This problem is quite complex and needs careful thinking. Before arriving at proper relay coordination and relay settings several factors have to be taken into account and several consequences are to be considered. The coordination criteria have to be decided both for overcurrent relays and distance relays.

For coordinating distance relays, first zone-1 is set to act instantaneously for faults on the protected line and the other two zones protect the main and adjacent lines with time delay increasing in discrete steps. A fully coordinated result should indicate the impedence setting values for all the zones in terms of various impedence taps available on the relays and also the timer settings associated with second and third zone relays.

For coordinating overcurrent relays, we require three parameters normally associated with any kind of

overcurrent relay; namely, the instantaneous tap value, the time-delay pick-up tap value and the time-dial setting value for all the relays in the system to satisfy the coordination criteria.

The relay performs both primary and back-up protection roles. Hence, one is concerned about the relative speed of operation of all primary/back-up pairs of relays; for proper coordination the primary relay must operate faster than the back-up for given fault currents. All relays are assumed directional and are sensitive only to currents flowing out of the bus on which they are located regardless of whether they are of overcurrent or distance type.

Coordination of relay pair must be achieved through detailed fault analysis under different situations. Coordination also takes into account the different contingencies such as single-line and double-line out contingencies for all faults. For example as shown in Fig. 1.1, primary and back-up pairs 1 and 3 must coordinate for faults at locations F_1, F_2 and F_3 when both lines DE and DF are in service and when DE is out of service or when DF is out of service and DE is healthy. Similar considerations hold good for other relay pairs as well.

A large number of computations are involved as the performance of such primary and back-up pairs must be checked for proper coordination involving each pair. For overcurrent

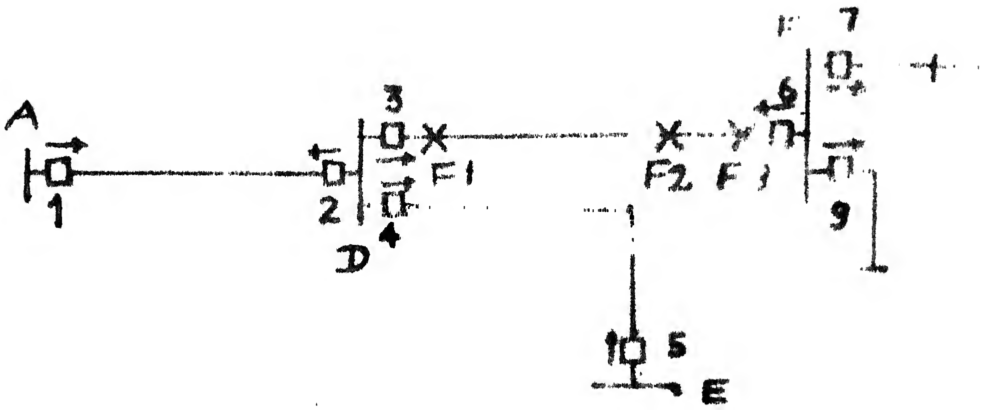


Figure 1.1

relays operating time of both the primary and back-up relays are computed to satisfy that back-up relay operates relatively or appropriately slower. If this fails for any fault current pairs, the settings of the primary and back-up must be altered. For distance relays apparent impedence seen upto the fault from relay location is computed. This is done for both primary and back-up relays.

There are several constraints which must be satisfied in the problem regarding relay coordination because any specific relay may function as primary for many faults and for each fault a number of other relays may function as back-up relay to this relay. Coordination constraints must be met for all primary and back-up pairs. Because same relay is back-up to a number of other relays which serve as primary for different faults. Hence, this relay must meet a different set of coordination constraints for these pairs. For example, as shown in Fig. 1.1, relay 3 participates in four primary/back-up pairs : viz., 3/1, 3/5, 7/3, 9/3. 3 is primary in first two and back-up in the last two. In the first case, it must coordinate with 1 and 5 for faults at F_1, F_2 and F_3 while in last two, it must coordinate with 7, 9 for all faults on the lines DE and DF respectively. All the relays in the network must simultaneously meet a similar large number of constraints.

At this time, it is possible that all constraints may not be satisfied with the existing relays and hence, it may be necessary to replace relays with ones of different characteristics or types.

Since the digital computer became available, it has been used as a tool in the analysis of various power system problems. Efforts were also made to focus attention on computarization of power system protection process. Initial efforts in this direction were reported by R.E. Albrecht et al.[1], where relay coordination program using a batch-off line approach was discussed in their paper "Digital computer protective device coordination program-I. General program description". A subsequent study by S.S. Begian et al.[2], followed a similar approach, giving more details about the various coordination criteria to be adopted in their work "a computer approach to setting overcurrent relays in a network". Yet another attempt in this direction was due to Thorn et al.[3] where only coordination of phase and ground distance relays was considered. Rockefeller, G.D. [4] suggested digital computer application in fault protection in his paper entitled "Fault protection with a Digital Computer". Ramamoorty, M. [5] implemented the methods to measure the impedence using digital computers. Mann, B.J. and Morrison, I.F. [6] suggested digital calculation of impedence for transmission line protection. Mann, B.J. and

Morrison, I.F. [7] suggested digital computer application for three-phase transmission line protection. Gokul, P., Sunak, V.P. and Singh, L.P. [8] suggested EHV transmission line protection using digital computers. Frequency domain analysis applied to digital transmission line protection was suggested by Carr, J. and Jackson, R.V. [9]. Hope, G.S. and Umamaheswaran, V.S. [10], followed a similar approach giving details about sampling for computer protection of transmission lines. Real time digital protection of transmission line was suggested by Hope, G.S., Malik, O.P. and Rasmy, M.E. [11]. A decentralised approach was suggested by Thirupathaiah, G., Varshney, A. and Singh, L.P. [12] in their paper "On line digital protection using a micro-computer". Phadke, A.G., Ibrahim, M. and Hlibka, T. [13] suggested fundamental basis for distance relaying with symmetrical components. Wiszniewski, A. [14] introduced a concept of error reduction in distance fault locating algorithms in his paper entitled "How to reduce errors of distance fault locating algorithms". Sunak, V.P. and Singh, L.P. [15] suggested microprocessor based protection scheme for EHV/UHV transmission line. McInnes, A.D. and Morrison, I.F. [16] suggested real time calculation of resistance and reactance for transmission line protection by digital computer. Poncelet, R. [17] described the use of digital computers for network protection. Bornard, P.

and Bastide, J.C. [18] developed a prototype of multi-processor based distance relay. The concept of digital impedence calculation using a single π section transmission line was introduced by Smolinski, W.J. [19] in his paper entitled "An algorithm for digital impedence calculation using a single π(pie) section transmission line". Rannbar, A.M. and Cory, B.J. [20], in their paper "An improved method for the digital protection of transmission line" suggested computer application in transmission line protection. Sachdev, M.S. and Baribean, M.A. [21] developed a new algorithm for digital impedence relay. Mortin, M.A. and Johns, A.J. [22] suggested a fundamental digital approach to the distance protection of EHV transmission lines. Girgis, A.A. and Brown, R.G. [23] suggested the application of Kalman filters in computer relaying. Islam, K.K. and Singh, L.P. [24] suggested broad areas of micro-processor application in power system protection. Digital protection of EHV transmission line was suggested by Gokul, P., Sunak, V.P. and Singh, L.P. [25]. Girgis, A.A. [26] brought out a new approach to Kalman filtering based digital distance relay. Digital distance relaying algorithms using different methods were discussed by Siyaram and Singh, L.P. [27], in their paper "Digital protection of transmission line".

Very recently R.B. Castineau et al.[28] have worked on iterative approach to solve the coordination problem. This approach starts with arbitrary relay coordination and proceeds until all the relays are properly coordinated. This envolves a large number of iterations through all the relays before the entire system is coordinated. A modified approach to solve this problem was given by Dwarkanath and Nowitz [29] where optimum starting points and sequence of coordination is discussed. More specific approach on this problem was by H.A. Smolleh [30] where a feasible model for time current characteristics of Industrial power system protective devices and for radial line relays are considered. A method to calculate settings for time-overcurrent relays was given by G.E. Radke [31]. H.Y. Tsien [32] suggested an automatic digital computer program for setting transmission line directional overcurrent relays. Venkata S.S. and Gamborg [33] applied graph theoretic approach to protection design.

In this thesis the input data required for setting the relays and coordinating them is generated by conducting short-circuit studies such as three-phase-to-ground, single-phase-to-ground and line-to-line faults, load flow studies for all contingencies (namely single-line and double-line out contingencies). Using the data so generated, operating time of different relays, their settings are calculated and checked for coordination. Iterative proceedure is followed for proper coordination of relays.

Chapterwise description of the work carried out and reported in this thesis is given below.

Chapter-2 discusses the coordination criteria required for relays. It discusses designed coordination criteria, minimum coordination criteria and enhanced criteria for both overcurrent and distance relays. For overcurrent relays the proce dure to determine instantaneous setting, pick-up tap setting and time-dial setting for two terminal as well as multiterminal lines are given. For distance relays the zone-1, zone-2 and zone-3 tap settings and zone-2 and zone-3 timer settings taking into account both, infeeds and outfeeds are discussed. In Chapter-3, required mathematical modelling for short-circuit studies, namely three-phase-to-ground, single-phase-to-ground and phase-to-phase faults are developed and short-circuit studies are carried out for all contingencies considered with minimum as well as maximum generation in the system at any time possible. A case study of CHUKHA TRANSMISSION SYSTEM is presented.

In Chapter-4 distance and overcurrent relay settings are determined using the input data generated by the study conducted n the previous chapter. For distance relays settings "apparent impedence seen" approach is followed and for overcurrent relays settings minimum and maximum possible fault currents through line under all contingency conditions are followed.

Chapter-5 discusses the coordination procedure for both, distance relays and overcurrent relays.

Chapter-6 discusses the results obtained by using the algorithms developed to set and coordinate distance relays and overcurrent relays used in CHUKHA TRANSMISSION SYSTEM : A TEST SYSTEM.

Chapter-7 concludes with the discussion on the findings of the present work and scope for the future developments.

CHAPTER-2

CO-ORDINATION CRITERIA

2.1 Introductory Remarks :

Identifying precisely and unambiguously, the relaying requirements and the coordination criteria is the primary task to be undertaken. In this chapter, we summarize the basic coordination criteria developed for overcurrent and distance relaying schemes. Only the general characteristic and coordination criteria are summarised in the following para. More detailed coordination proceedures are discussed later.

2.2 Classification of Criteria :

Three broad categories for coordination criteria are defined:

Desired design criteria : These are the existing criteria which will result in desired operation of the relay system.

Minimum criteria : These are the criteria adopted when the desired criteria can not be achieved. This is achieved through back-up relay operating time being relaxed i.e. allow back-up relay not to operate for some low fault currents.

Enhanced criteria : These are the criteria designed to produce optimum results. It might include consideration of additional fault at mid-line for the purpose of coordination.

2.3 Directional Instantaneous/IDMT Overcurrent Relays :

2.3.1 Characteristics :

a. Instantaneous overcurrent relays : If relay operates instantaneously without any internal time delay; this characteristic can generally be satisfied by a relay of non-polarized attracted armature type. Instantaneous relay is effective only when the impedence between the relay and source (Z_s) is small compared to the protected section impedence Z_e.

In the case of instantaneous relays, there is a tendency for oversensitivity under transient fault currents with D.C. component. At the time of fault occurance, the current wave is not symmetrical but offset as shown in Fig. 2.1. The relay is set for symmetrical currents but responds to both symmetrical as well as offset current waves which persist for a few cycles. The overreach depends on the design of the relay as well as on the parameters of the power system on which it is used. The X/R ratio from the source to the fault of the system, controls the degree of offset and rate of decrement of

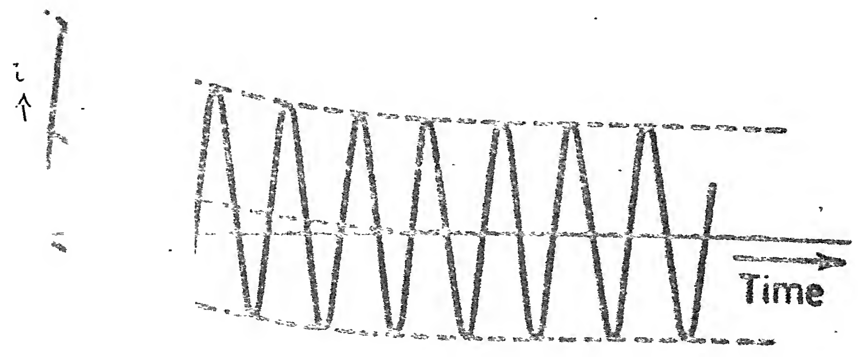


Fig. 2.1 offset current wave

current wave, and the ratio Z_s/Z_e determines the degree of overreach, which will occur.

The current setting is proportional to $\frac{1}{(Z_s+Z_e)}$ so that with 100% offset, the pick-up will occur with half the symmetrical value of current i.e.

$$\text{Operating current} \propto \frac{1}{2(Z_s+Z_e)}$$

Since Z_s is fixed, the effective length of the line protected is increased consequently there is overreach. If K be the overeach, then

$$Z_s + KZ_e = 2(Z_s+Z_e) \Rightarrow \qquad K = 2 + \frac{Z_s}{Z_e}$$

i.e. with 100% offset current wave, the instantaneous o/c relay will overreach to more than twice the length of the protected section.

Actually, the overreach will be reduced by the operating time of the relay because the d.c. component of the fault current will be decaying exponentially, so that

$$i = \frac{E_{max}\,\mathrm{Sin}(\omega t + \psi - \phi)}{R^2 + (\omega L)^2} + \frac{E_{max}\, e^{-Rt/L}\,\mathrm{Sin}(\psi - \phi)}{R^2 + (\omega L)^2}$$

$$\Rightarrow \; i = I_{max}\left[\mathrm{Sin}(\omega t + \psi - \phi) + A\, e^{-Rt/L}\right]$$

ϕ : phase angle of the circuit.

ψ : time in radians after time zero at which fault occurs and

t : time after inception of fault.

D.C. filters are used to overcome the overreach due to transients. Sometimes induction cup instantaneous units are used as they are less sensitive to d.c. offset components. This way transient overreach is reduced to approximately 5%.

b. Overcurrent relays : The operating time of all o/c relays tends to become asymptotic to a definite minimum value with increase in the value of current. This is due to the saturation of magnetic circuit of electromagnetic relays. So, by varying the degree of saturation different characteristics are obtained. These relays are usually built using static components. In both cases, their characteristics remain same. These characteristics are :

		Approximate equation
(a)	Definite Time	$I^{\emptyset}t = K$
(b)	Inverse definite minimum time (IDMT)	$It = K$
(c)	Very inverse	$I^2t = K$
(d)	Extremele inverse	$I^3t = K$

(in general $I^n t = K$)

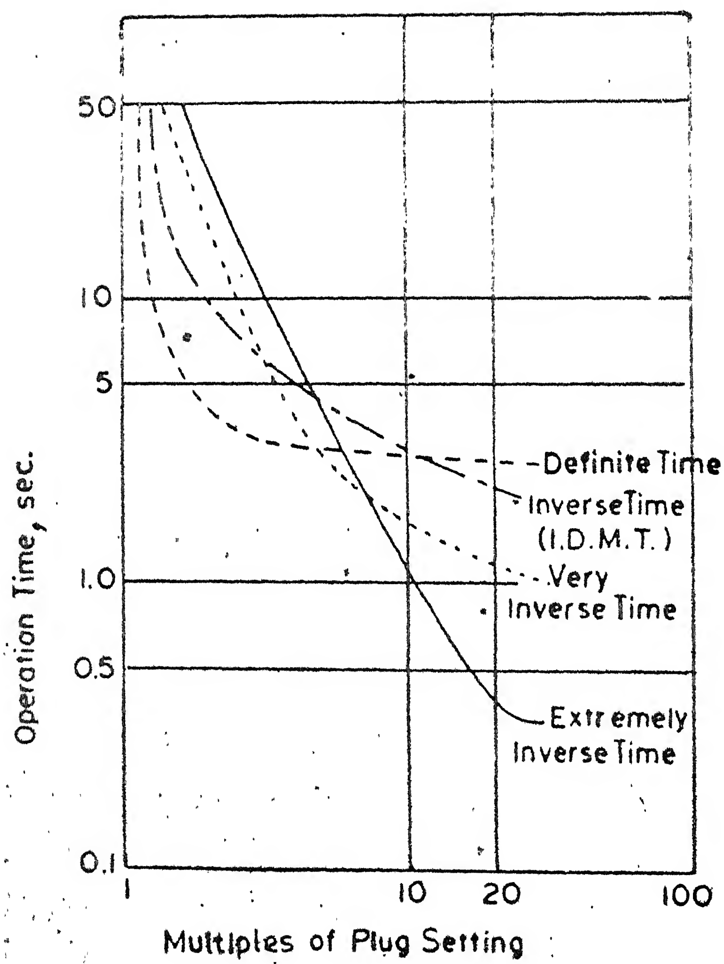
Characteristics of various overcurrent relays are shown in Fig. 2.2.

Definite time relay is employed in cases of wide variations of system generating conditions. Another possible application is the differential protection of transformers to prevent maloperation during magnetisation due to inrush currents. Definite time feature when used with inverse characteristic is more useful-gives inverse with definite time characteristic as used in protection of Induction motor against overloads. Definite time is preferred to instantaneous to serve as a check against short-time a symetrical currents.

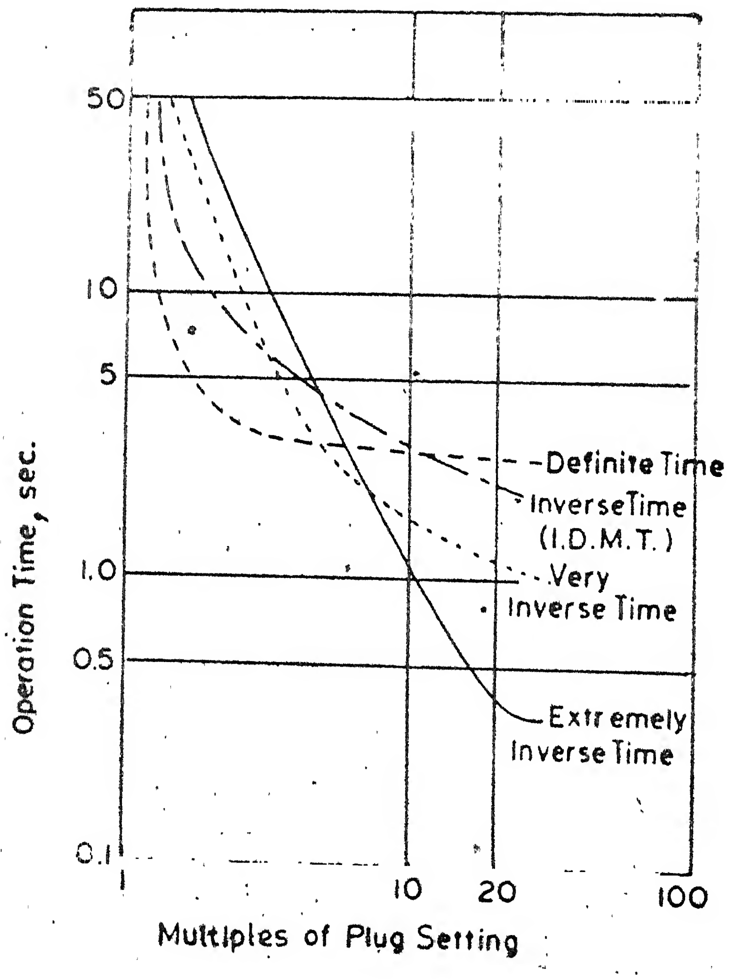
Very inverse characteristic is employed where the source impedence is much smaller than the line impedence. These are more suitable for earth fault protection as there is a greater variation of zero sequence currents with distance than with phase faults.

Fuse coordination and thermal protection of transformers and induction motors require such characteristics They are useful, in conjunction with negative sequence filters to protect against unbalanced operation of generators.

The operating time of overcurrent relays is a function of:



50
10
5
1.0
0.5
0.1
1
10
20
100
Operation Time, sec.
Multiples of Plug Setting
Definite Time
Inverse Time (I.D.M.T.)
Very Inverse Time
Extremely Inverse Time



50
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1.0
0.5
0.1
1
10
20
100
Operation Time, sec.
Multiples of Plug Setting
Definite Time
Inverse Time (I.D.M.T.)
Very Inverse Time
Extremely Inverse Time

i) Current through the relay

ii) Pick-up current tap setting

iii) Time-dial setting.

2.3.2 Co-ordination Criteria :

Two terminal lines :

a. Instantaneous setting : It is specified in terms of threshold current above which the relay trips. The relay should be set to protect the fault on the primary line and should include a factor of safety to prevent against false trips for faults on the remote bus. Thus the setting will be given by

$$\text{Setting of instantaneous relay} = MF_{IA} \times \text{Max. current for a fault on remote bus}$$

This maximum fault current is maximized over all fault types and all single line out contingencies, namely, one line out at a time.

Generally MF_{IA} (multiplying factor for instantaneous action) is taken to be 1.2 to 1.3. The reason being to avoid overreaching causing false trip. As shown in Fig. 2.3 on page no.23

Faults F_1, F_2 and F_3 will produce almost same current through relay 4 but it is not desirable to trip relay 4 for

faults at F_2 and F_3 as 4 is back-up to them. Hence for instantaneous setting faults is created at F_1 and the quantity obtained is multiplied by a factor (1.2 - 1.3) to avoid overreaching.

Time-Delay operation setting :

b. Pick-up tap setting : To set the pick-up tap of o/c relay allowable range of tap values is determined by computing the following upper and lower limits. The lower limit is determined by max. possible load current taking into account the overload and power swing conditions for phase protection and tolerable unbalance factor for ground protection.

$\therefore$ Lower limit of pick-up tap = LCF X Max. load current (phase protection)

Lower limit of pick-up tap = CTU X Max. load current (ground protection)

Typically LCF (Load carrying factor) = 1.25 - 1.5

CTU (Tolerable unbalance factor) = 0.05 - 0.1

The upper limit is the smaller of :

b_1 : Normal remote bus fault current X factor (NRBFF) This factor should be so chosen that normal remote bus fault current is 5 to 1o times that of normal load current (all lines in service, 3-$\emptyset$ fault for

phase protection, 1-∅ to ground fault for ground protection).

b_2 : Minimum fault current through the relay X Factor (MFCF) This factor (MFCF) accounts for condition generally prevailing in power system that minimum fault current (phase-to-phase fault with minimum generation gives minimum fault current of all) is one and half or two times greater than normal load current.

Hence

MFCF (Minimum Fault Current Factor) : 0.5 to 0.6

The upper limit ensures that relay is set sensitive enough for all the fault current levels. One is free to select any value within this range, value near the lower end results in most sensitive back-up relaying.

c. Time-Dial Setting : Time-dial settings are determined from the following criteria :

1. Desired design criteria : The operating time of the back-up relay should exceed that of its corresponding primary relay for all the faults considered (all fault types, normal and single-contingency conditions) by a coordination time-interval MCI.

   The actual value of coordination time is arrived as follows :

MCI = TIB(P) + TOT(B) + COFS

TIB(P) : short circuit interupting time of primary breaker

TOT(B) : overtravel time of back-up relay

COFS : factor of safety

Typical values of the above factors are :

TIB(P) : 0.050 secs (3 cycles)

TOT(B) : 0.1667 secs (10 cycles)

COFS : 0.0833 secs (5 cycles)

∴ MCI = 0.3 secs.

When local breaker failure protection is used then MCI should consider the delay involved with local back-up schemes.

It is desirable to maintain the desired coordination time interval of 0.3 secs between primary and back-up operating times for a class of faults like remote bus fault, close in fault, line end faults and fault at the reach of instantaneous trip. If verified for remote bus fault, then it satisfies with others as well.

2. Minimum criteria : Under those circumstances that demand a relaxation of the above specified criteria, the actual setting must minimize the impact on power supply. That is, the number of customers or the amount

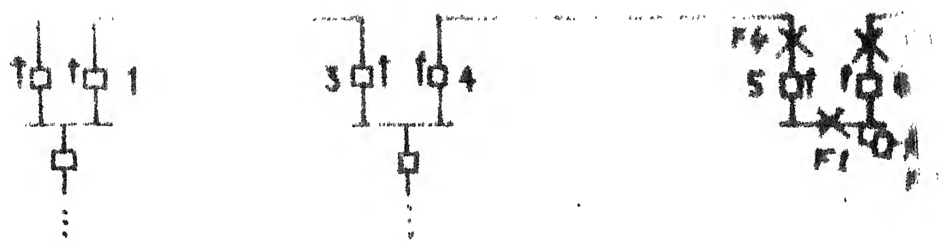


FIGURE 2.3

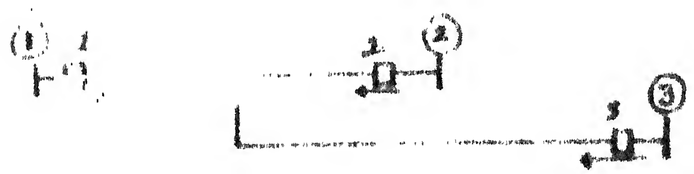


FIGURE 2.4

of load affected by the compromise of relay settings should be kept at minimum. Of the fault currents indicated under desired criteria, a relaxed minimum criterian will be to allow the back-up relay not to operate for some low fault currents.

3. Enhanced criteria : This criterian might include the consideration of faults at mid of the lines and checking for coordination of the relays.

Multi-Terminal Lines : As shown in Fig. 2.4 a single line terminates at two different buses. To take into account the existence of more than one remote bus, the coordination criteria is altered as follows. The instantaneous unit is to be set at MF_{IA} X Max. of all fault currents at all the remote buses.

Additional Considerations : Overcurrent relays can not be used in cases where the fault current levels are below the max. load current value. However, voltage restrained directional overcurrent relays may be employed in these cases or, for phase protection, supervising distance relays can be used.

If relays are coordinated for high current values, they will usually be coordinated for low-current values also due to their inverse characteristics. But the converse is not true. Hence while coordinating overcurrent relays, generating conditions producing max. fault currents must be

considered to ensure that relays are properly coordinated through the entire range of generations.

2.4 Directional Multizone Distance Relays :

2.4.1 Characteristics :

The conventional distance relaying uses three distance measuring units. These relays measure the distance to a fault by measuring line impedence between the fault and relay location. These relays may be of impedence, angle impedence i.e. ohm or angle admittance i.e. mho, offset mho and modified i.e. restricted impedence relay, elliptical characteristic, quadrilateral characteristic type. The characteristics on the complex plane are shown in Fig. 2.5.

Multiple zones of protection are achieved by coupling step-time delay units to relay units that measure the distances beyond the first zone with the time delay increasing with zone.

Zones of prptection using distance relaying scheme aregenerally insensitive to system changes with the exception that infeeds and outfeeds will alter the reach.

First-zone which involves instantaneous action, is set to about 0.8 to 0.9 the distance to the end of the protected line for primary protection without any concern

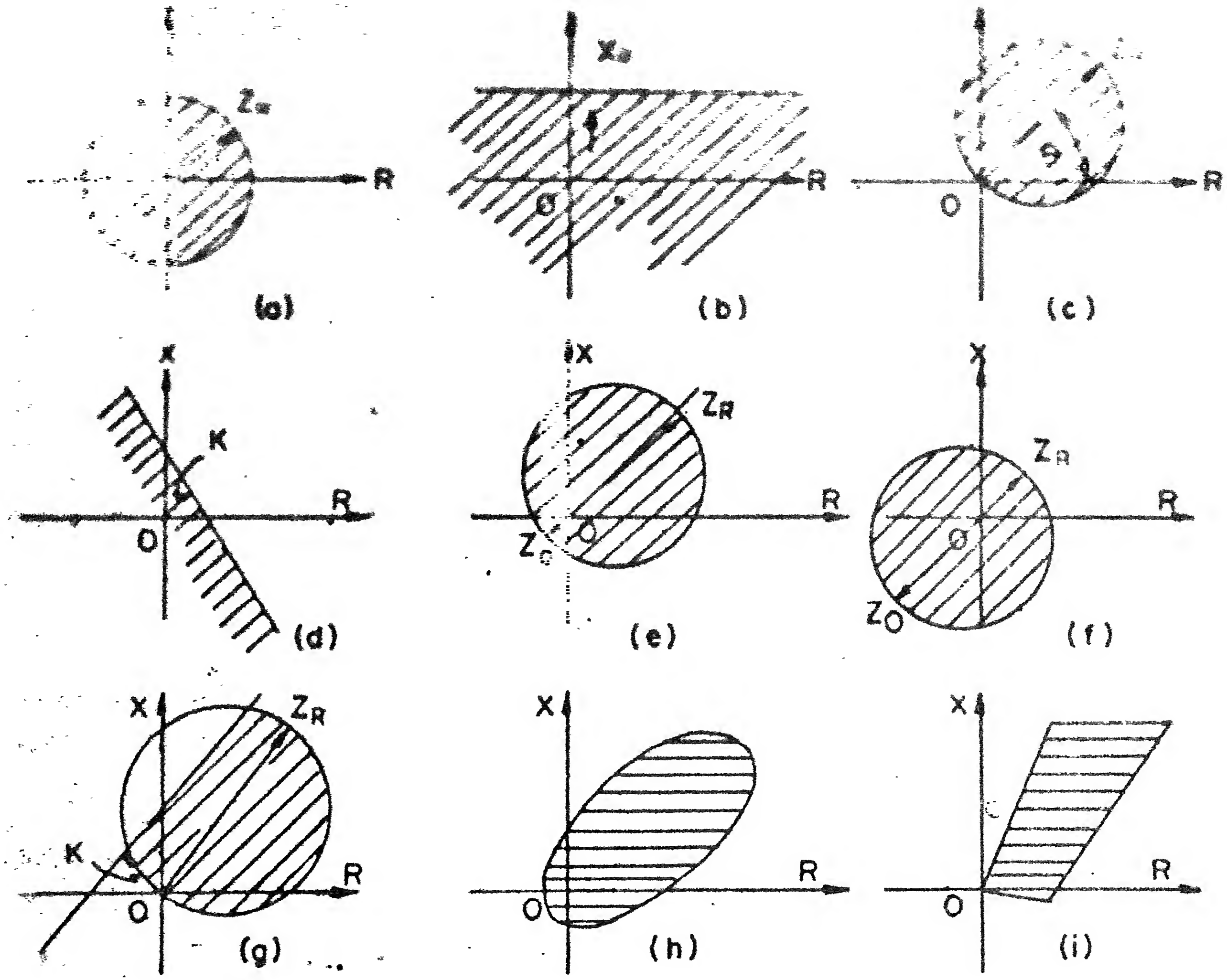


Fig 2.5 Distance relay characteristics

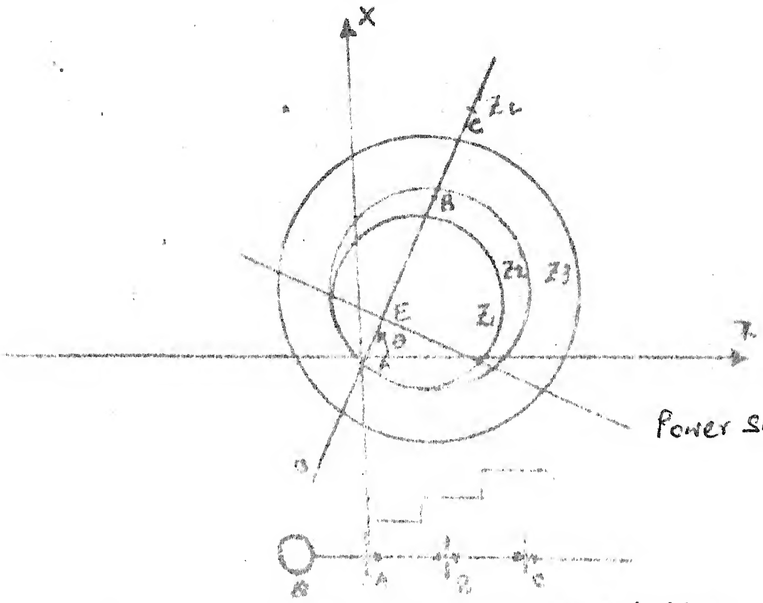


Fig 2.6 : Offset Mho's characteristics

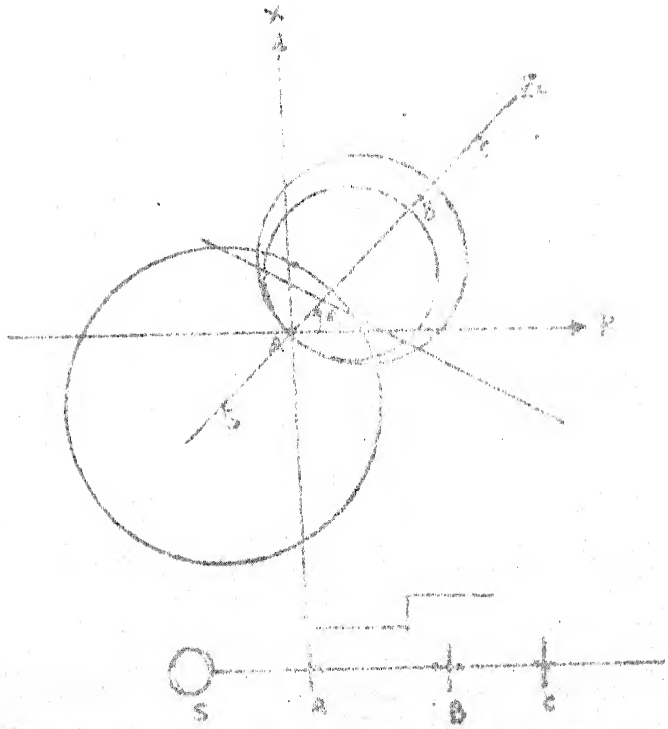


Fig 2.6A : Offset Mho's characteristics with Z-3 reversed

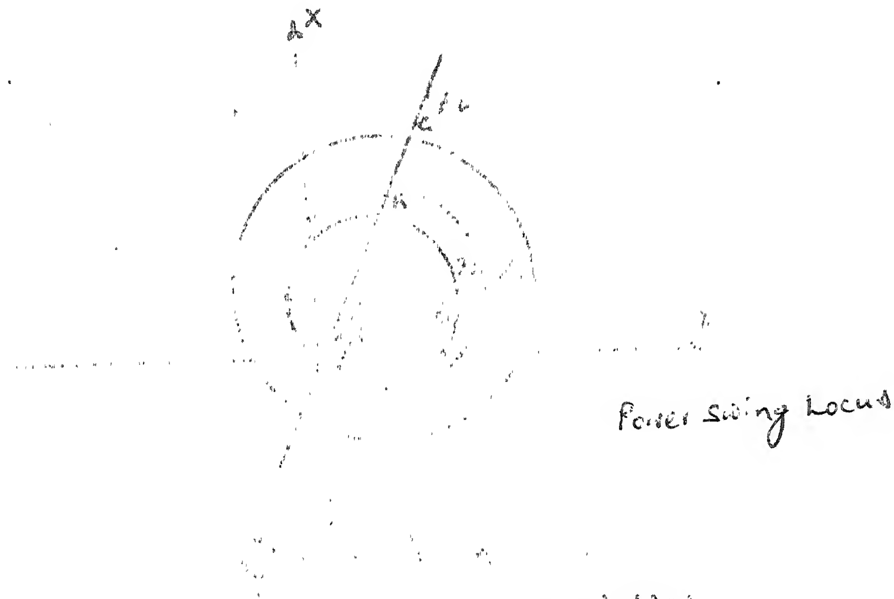


Fig 2.6 : Offset Mho's characteristics

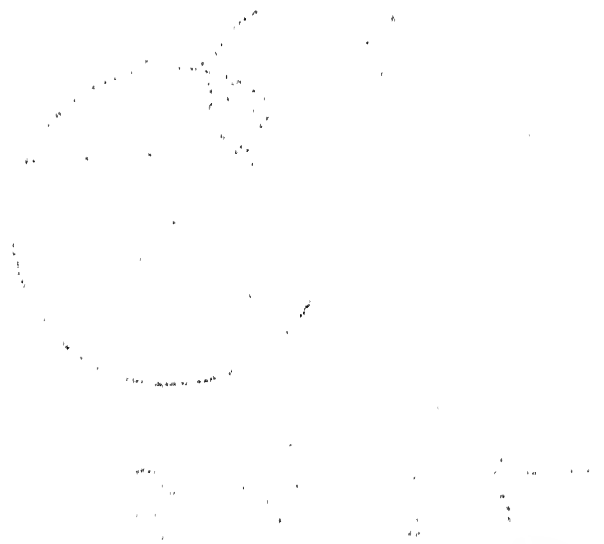


Fig 2.6A : Offset Mho's characteristics with Z-3 reversed

protected section, alleviates these problems considerably. The characteristic for this action is shown in Fig. 2.6 A.

2.3.2 Co-ordination Criteria :

Two terminal lines :

Desired criteria : Under the normal provision of three zones of protection, one with instantaneous action and two with increasing time delays, both primary and back-up protection are obtained for all phase faults. Faults are to be cleared with a time delay not greater than maximum allowed delay time (say 2.0 seconds) and sequential breaker action is to be coordinated with a minimum time delay of 0.3 sec, normally. These criteria are to be met when infeeds from all branches within the zones are considered.

Coordination criteria for individual zones are summarised below :

Zone 1, used for primary protection, is set to 0.8 to 0.9 times primary line impedence for instantaneous action. For fault in zone-1, this relay trips instantaneously.

Zone-2 protects line beyond the range of zone-1 and also is set to cover remote bus plus some portion of next line.

Setting for second zone = 1.25 to 1.5 times primary line impedence.

It is to be checked that it does not overlap with the second zone of other distance relays.

The relay trips with a time delay referred to as zone-2 time delay T2 for faults in zone-2. Generally T2 is taken to be 0.3 secs.

Zone-3 is used for back-up protection and it is desirable to set it to the entire length of the longest remote line. However, it should be limited by worst loading conditions. This zone should be properly coordinated with other third zones of relays on the remote lines. Time delayed tripping due to fault in this zone i.e. T3 should be less than maximum permissible time delay operation for distance relays.

Minimum criteria : In extreme cases where, due to various infeed effects, the time coordination for second and third zones may not be possible. In these cases, the minimum criteria is to assume a sequence of relay tripping which reduces the infeed effects and eventually isolates the fault. With the help of the example shown in Fig. 2.7, minimum criterian requirement will become clear.

Relays 1 and 2 provide back-up for 5. Consider relay 1 which senses faults F_1 and F_2 with its second and third zones when feed from BC was not there. But if this feed is present, then zone-2 and 3 of relay 1 may under reach causing F_2 not being sensed and F_1 may fall under the zone-3 of

this relay. However, if relay 2 detects the fault F_1 and F_2 in it's zone-2 and 3 region and trips, the infeed no longer exist. Now F_1 and F_2 falls within zone-2 and 3 of relay 1 which trips. This is especially important for multi-terminal lines.

Enhanced criteria : The desired criteria are to be extended to more than one level of back-up protection (second contingency conditions such as two successive relay/breaker failures) using more than three zones of protection.

Multi-terminal lines : Because of presence of infeed and outfeed, the apparent impedence seen by the relays changes. Let us refer to Fig. 2.8 where an effect of infeed is considered and next to Fig. 2.9 where an effect of outfeed is considered.

Apparent impedences seen by relay 5 and 6 for fault at F with zero fault impedence are

$$Z_{Ap}(5) = Z_{HF} + \left(\frac{I_D}{I_H}\right) Z_{JF} \quad \text{and}$$

$$Z_{Ap}(6) = Z_{DF} + \left(\frac{I_H}{I_D}\right) Z_{JF}$$

Thus, the apparent impedence seen by the relay will be greater than the actual one. Apparent impedence should not be considered for setting zone-1, since absence of infeed will stretch zone-1 reach beyond next bus. Zone-1 setting should be 0.8 to 0.9 times smallest line length

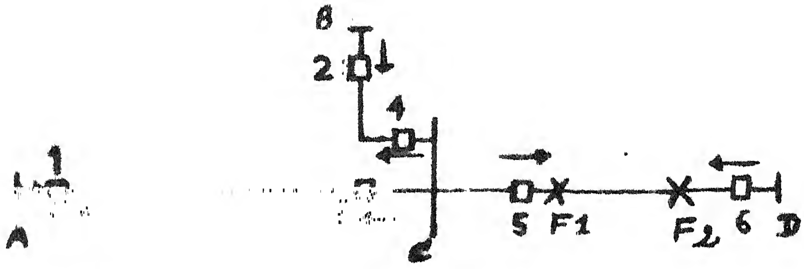


Figure 2.7 : General Transmission Line

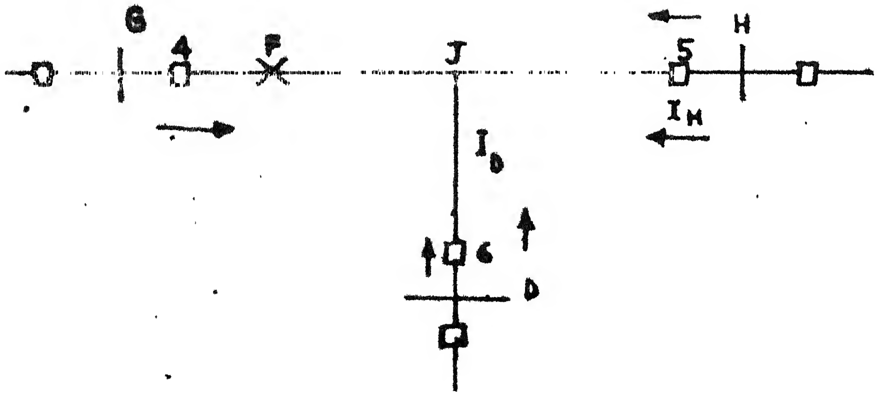


Figure 2.8 —: INFEED EFFECT :—

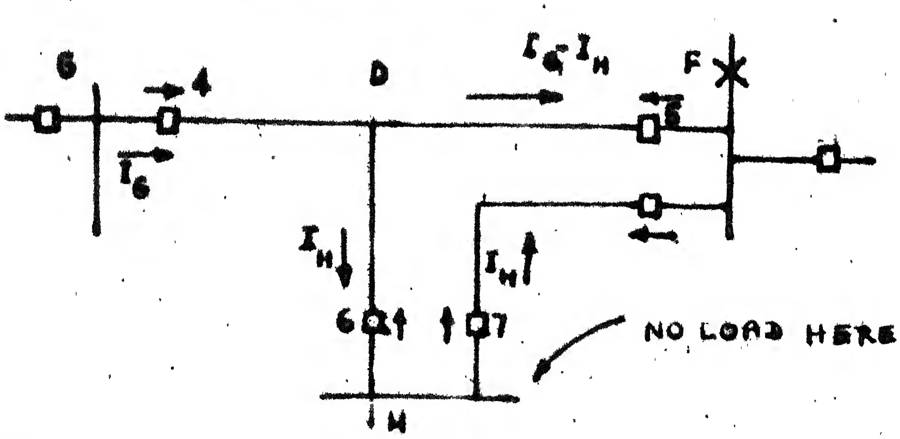


Figure 2.9 : OUTFEED EFFECT

(equivalent impedence) from each relay point. For second zone setting, it must be ensured that all remote buses are included in this zone. Thus, it must be set above the maximum apparent impedence to any remote terminal. The third zone should be set beyond zone-2 to back-up the longest remote line. Considering outfeeds shown in Fig. 2.9.

For fault at F;

apparent impedence seen by relay 4

$$Z_{Ap}(4) = (Z_{GD} + Z_{DF}) - (\frac{I_H}{I_D}) Z_{DF}$$

hence apparent impedence is less than actual impedence and thus it tends to overreach.

Here also, zone-1 setting should be 0.8 to 0.9 times smallest line length (equivalent impedence) from each relay location. Second zone should be set above the max. apparent impedence to any remote terminal to ensure that all remote buses are included in this zone. Third zone setting should be above second zone backing up the longest remote line.

Minimum criteria : When unequal lengths are involved in three terminal line and the line is accompanied by short adjacent lines, the second zone setting of max. apparent impedence may result in poor coordination in zone-2 setting.

In this case, zone-2 setting can be reduced to a smaller length and the zone-3 setting may be adjusted to cover all the remote buses of three-terminal line.

In the extreme cases, where very long line and a very small line radiate from remote bus pilot relaying for small line is desirable.

CHAPTER-3

FAULT ANALYSIS

3.1 Introductory Remarks :

In order to provide appropriate data for designing the protection scheme i.e. both the protective relays and circuit breakers, currents and voltages resulting from various types of faults occuring at different locations throughout the power system network are required.

Intensive calculations of voltages and currents due to various faults at different locations necessitate the use of digital computer. Short-circuit studies and hence fault analysis are very important as they provide data such as voltages and currents during and after faults which are necessary in designing appropriate protection schemes. Currents that flow just after the occurance of faults, that flow a few cycles later and steady state values of the fault currents differ very much from each other. Different type of faults in power systems are :

(i) 3-Ø direct short-circuit (LLL) or 3-Ø fault through fault impedence LLL(G)

(ii) 1-Ø-G fault with or without fault impedence (L-G)

(iii) Line-to-line direct short-circuit or through fault impedence (L-L)

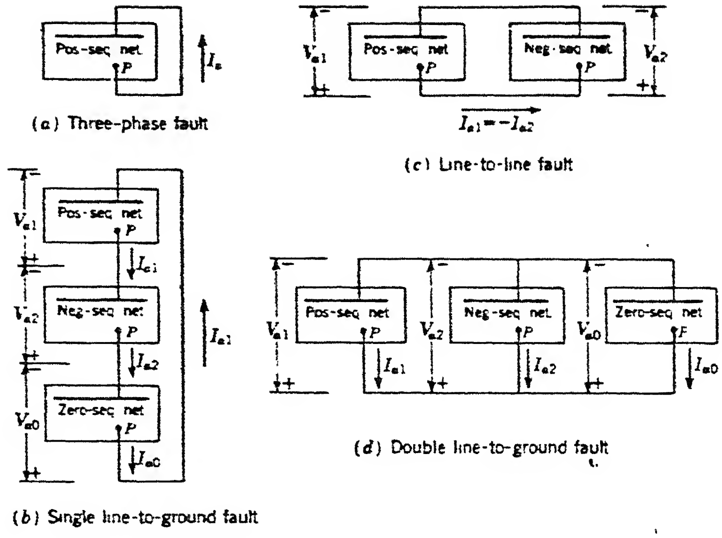
(iv) Double-line-to-ground fault with or without fault impedence.

In case of (i) system remains balanced after the fault. However in cases (ii), (iii) and (iv) the excitation becomes nonsymmetrical even though the network element is balanced i.e. these are such asymmetrical component quantities since after transformation the component quantities through equations becomes uncoupled even though it were coupled earlier before transformation. Only positive sequence network will have a voltage source, since excitation voltage of synchronous generator 'E_g' or prefault voltage 'V_f' is balanced i.e. there are only positive sequence voltages. There is no voltage source in negative and zero sequence networks. Moreover, the neutral of the system is only for positive and negative sequence networks but ground is the reference for zero sequence network and hence only zero sequence current flows if the circuit from the neutral to ground is complete in the element between neutral of power system and the ground.

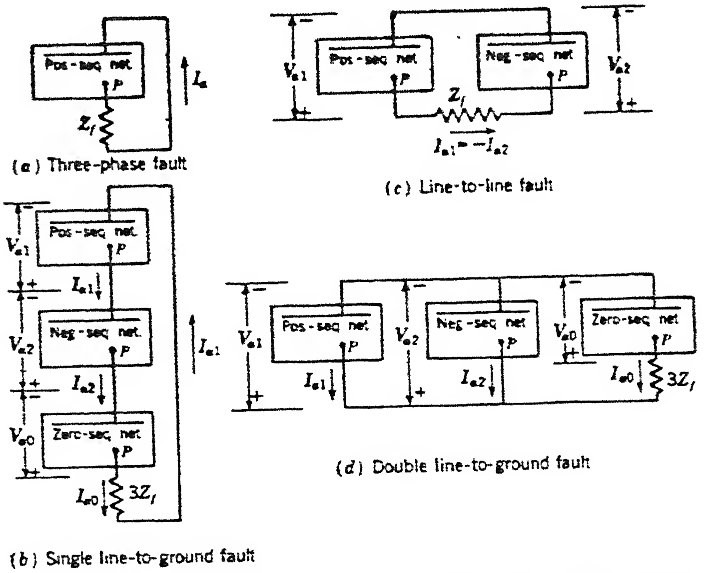
For all of the faults discussed the sequence network connections are shown in Fig. 3.1.

3.2 Problem Formulation :

In this part a method to simulate these faults on the digital computer is presented. For short-circuit



Connections of the sequence networks to simulate various types of faults. The sequence networks are indicated by rectangles. The point at which the fault occurs is P.



Connections of the sequence networks to simulate various types of faults through impedance at point P.

Fig 3.1 : sequence network connection

studies following assumptions are made :

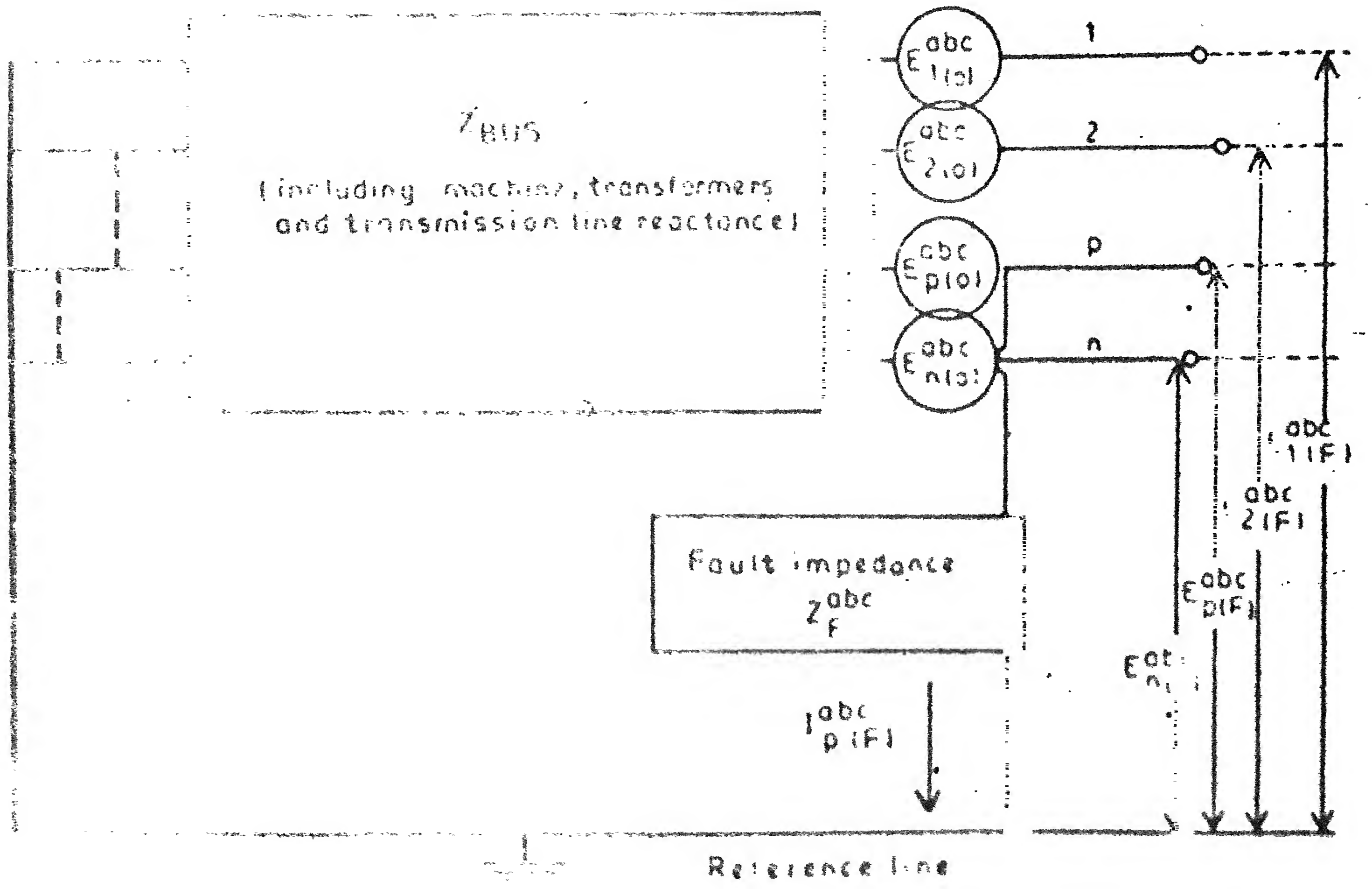
(i) Representing each machine by a constant voltage source behind proper reactance which may be sub-transient, transient or steady-state reactances.

(ii) Neglecting all the shunt connections such as static loads, line charging and transformer magnetising circuits. Thus normal load currents are neglected, therefore, all prefault bus voltages will have the same magnitude and phase angle. Thus to work on per unit system, the prefault bus voltages are set equal to $1\underline{/0}$.

(iii) Setting all the transformers to nominal taps (i.e. transformer tappings are neglected). Thus in per unit system transformer will be out of circuit.

(iv) Normally, neglecting winding resistances and line resistances etc. With this assumption system will contain only reactances. This assumption is made for short circuit studies on the D.C. analyser. For studies conducted on digital computer, this assumption is usually not made, at least transmission lines resistances are not neglected.

By taking into account all the assumptions, the power system network will be represented as shown in Fig. 3.2 for a fault at bus P. The elements of Z(Bus) matrix include parameters of machines, transformers and transmission lines. This representation is derived by Thevenin's theorem; include Z(Bus) matrix



Power system representation for a fault at bus *p*

Fig 3-2

as defined in series with open circuit voltages (i.e. $E^{ab}_{1(0)}$, $E^{ab}_{2(0)}$...), where open circuit voltages will be equal to prefault bus voltages.

The performance eqn. in the bus frame of ref. using Z(Bus) of a power system when fault occurs at any bus P, will be given by,

$$\begin{bmatrix} E^{abc}_{1(F)} \\ E^{abc}_{2(F)} \\ \vdots \\ E^{abc}_{P(F)} \\ \vdots \\ E^{abc}_{n(F)} \end{bmatrix} = \begin{bmatrix} E^{abc}_{1(0)} \\ E^{abc}_{2(0)} \\ \vdots \\ E^{abc}_{P(0)} \\ \vdots \\ E^{abc}_{n(0)} \end{bmatrix} - \begin{bmatrix} Z^{abc}_{11} & \cdots & Z^{abc}_{1P} & \cdots & Z^{abc}_{1n} \\ Z^{abc}_{21} & \cdots & Z^{abc}_{2P} & \cdots & Z^{abc}_{2n} \\ \vdots & & & & \\ Z^{abc}_{P1} & \cdots & \cdots & \cdots & Z^{abc}_{Pn} \\ \vdots & & & & \\ Z^{abc}_{n1} & \cdots & \cdots & \cdots & Z^{abc}_{nn} \end{bmatrix} \begin{bmatrix} 0 \\ 0 \\ \vdots \\ I^{abc}_{PF} \\ \vdots \\ 0 \end{bmatrix} \quad (1)$$

Hence, after the fault occurs through the fault impedence/admittance, we calculate first of all the bus voltages. After this, the fault currents flowing in the element of the power system are determined.

Bus voltages for faulted bus P, given by

$$E^{abc}_{P(F)} = Z^{abc}_{F} \; I^{abc}_{P(F)} = Z^{abc}_{F} \; [Z^{abc}_{F} + Z^{abc}_{PP}]^{-1} \; E^{abc}_{P(0)} \quad (2)$$

For other buses than faulted one,

$$E_{i(F)}^{abc} = E_{i(0)}^{abc} - Z_{iP}^{abc} \; I_{P(F)}^{abc} \quad ; \; i = 1,2,\ldots.n \qquad (3)$$

$$i \neq P$$

$$E_{i(F)}^{abc} = E_{i(0)}^{abc} - Z_{iP}^{abc} \left[Z_{F}^{abc} + Z_{PP}^{abc}\right]^{-1} E_{P(0)}^{abc} \qquad (4)$$

$$I_{P(F)}^{abc} = \left[Z_{F}^{abc} + Z_{PP}^{abc}\right]^{-1} E_{P(0)}^{abc} \qquad (5)$$

Of fault admittance is given then

$$E_{P(F)}^{abc} = \left[U + Z_{PP}^{abc} \; Y_{F}^{abc}\right]^{-1} E_{P(0)}^{abc} \qquad (6)$$

$$I_{P(F)}^{abc} = Y_{F}^{abc} \left[U + Z_{PP}^{abc} \; Y_{F}^{abc}\right]^{-1} E_{P(0)}^{abc} \qquad (7)$$

Similarily voltages at the other buses than faulted one,

$$E_{i(F)}^{abc} = E_{i(0)}^{abc} - Z_{iP}^{abc} \; I_{P(F)}^{abc}$$

$$E_{i(F)}^{abc} = E_{i(0)}^{abc} - Z_{iP}^{abc} \; Y_{F}^{abc}\left[U + Z_{PP}^{abc} \; Y_{F}^{abc}\right]^{-1} E_{P(0)}^{abc} \qquad (8)$$

The fault current in any element i-j of the power system network will be

$$i_{ij(F)}^{abc} = \left[y_{ij\beta\sigma}^{abc}\right] \left[E_{\beta(F)}^{abc} - E_{\sigma(F)}^{abc}\right]$$

$y^{abc}_{ij\beta\sigma}$ is the 3-ϕ element of the primitive network.

$E^{abc}_{\beta(F)}$ and $E^{abc}_{\sigma(F)}$ are bus voltages after the fault at any bus β and σ.

All the above eqns. can be transferred into component quantities :

$$I^{012}_{P(F)} = [Z^{012}_{F} + Z^{012}_{PP}]^{-1} E^{012}_{P(0)}$$

$$I^{012}_{P(F)} = Y^{012}_{F}[U + Z^{012}_{PP} Y^{012}_{F}]^{-1} E^{012}_{P(0)}$$

$$E^{012}_{P(F)} = Z^{012}_{F}[Z^{012}_{F} + Z^{012}_{PP}]^{-1} E^{012}_{P(0)} \tag{9}$$

$$E^{012}_{P(F)} = [U + Z^{012}_{PP} Y^{012}_{F}]^{-1} E^{012}_{P(0)}$$

$$E^{012}_{i(F)} = E^{012}_{i(0)} - Z^{012}_{iP}[Z^{012}_{F} + Z^{012}_{PP}]^{-1} E^{012}_{P(0)}$$

$$E^{012}_{i(F)} = E^{012}_{i(0)} - Z^{012}_{iP} Y^{012}_{F}[(U + Z^{012}_{PP} Y^{012}_{F})]^{-1} E^{012}_{P(0)}$$

$$i = 1,2,\ldots\ldots n$$

$$i \neq P$$

$$i^{012}_{ij(F)} = y^{012}_{ij\beta\sigma}[E^{012}_{\beta(F)} - E^{012}_{\sigma(F)}]$$

3.2.1 Algorithms for Calculating System Conditions after the occurance of faults :

3.2.A1. 3-Ø to ground fault through fault impedence Z_f per phase :

Let the fault occurs at the bus P through fault impedence Z_f and finite ground impedence Z_g. For this case, fault impedence matrix, i.e. Z_F^{abc} in the bus frame of reference is developed by conducting open circuit test. It is given by

$$Z_F^{abc} = \begin{bmatrix} Z_f + Z_g & Z_g & Z_g \\ Z_g & Z_f+Z_g & Z_g \\ Z_g & Z_g & Z_f+Z_g \end{bmatrix}$$

In symmetrical component form,

$$Z_F^{012} = \begin{bmatrix} Z_f + 3Z_g & 0 & 0 \\ 0 & Z_f & 0 \\ 0 & 0 & Z_f \end{bmatrix}$$

$$\therefore\ I_{P(F)}^{012} = [Z_F^{012} + Z_{PP}^{012}]^{-1}\ E_{P(0)}^{012}$$

$$\begin{bmatrix} I_{P(F)}^{(0)} \\ I_{PC(F)}^{(1)} \\ I_{P(F)}^{(2)} \end{bmatrix} = \begin{bmatrix} Z_f + 3Z_g + Z_{PP}^{0} & 0 & 0 \\ 0 & Z_f + Z_{PP}^{1} & 0 \\ 0 & 0 & Z_f + Z_{PP}^{2} \end{bmatrix}^{-1} \begin{bmatrix} 0 \\ \sqrt{3} \\ 0 \end{bmatrix}$$

$$\begin{bmatrix} I_{P(F)}^{(0)} \\ I_{P(F)}^{(1)} \\ I_{P(F)}^{(2)} \end{bmatrix} = \begin{bmatrix} 0 \\ \dfrac{\sqrt{3}}{Z_f + Z_{PP}^{(1)}} \\ 0 \end{bmatrix} \tag{1}$$

Similarily,

$$\begin{bmatrix} E_{P(F)}^{0} \\ E_{P(F)}^{1} \\ E_{P(F)}^{2} \end{bmatrix} = \begin{bmatrix} 0 \\ \dfrac{\sqrt{3}\, Z_f}{Z_f + Z_{PP}^{(1)}} \\ 0 \end{bmatrix} \tag{2}$$

Voltage at other buses

$$\begin{bmatrix} E_{i(F)}^{0} \\ E_{i(F)}^{1} \\ E_{i(F)}^{2} \end{bmatrix} = \begin{bmatrix} 0 \\ \sqrt{3} \\ 0 \end{bmatrix} - \begin{bmatrix} Z_{iP}^{0} & 0 & 0 \\ 0 & Z_{iP}^{1} & 0 \\ 0 & 0 & Z_{iP}^{2} \end{bmatrix} \begin{bmatrix} 0 \\ \dfrac{\sqrt{3}}{Z_f + Z_{PP}^{(1)}} \\ 0 \end{bmatrix}$$

$$\begin{bmatrix} E^{0}_{i(F)} \\ E^{1}_{i(F)} \\ E^{2}_{i(F)} \end{bmatrix} = \begin{bmatrix} 0 \\ \sqrt{3} \\ 0 \end{bmatrix} \begin{bmatrix} 0 \\ 1 - \dfrac{Z^{1}_{iP}}{Z_f + Z^{(1)}_{PP}} \\ 0 \end{bmatrix} \qquad (3)$$

To calculate fault current in the element of power system,

$$\therefore \quad y^{(1)}_{ij\beta\sigma} = 0 \quad \text{except for the element } ij = \beta\sigma$$

Thus the fault current in any element i-j is given by,

$$\begin{bmatrix} i^{0}_{ij(F)} \\ i^{1}_{ij(F)} \\ i^{2}_{ij(F)} \end{bmatrix} = \begin{bmatrix} 0 \\ y^{(1)}_{ij,ij} \, [E^{11}_{i(F)} - E^{(1)}_{j(F)} \\ 0 \end{bmatrix}$$

Here, we have only positive sequence network consisting of positive sequence impedence.

3.2.A2. Line-to-line fault through Z_f :

Let us take line-to-line fault at any bus P between any of the two phases, say b to c through a finite fault impedence Z_f per phase.

Clearly Z_F^{abc} is undefined, however elements of fault admittance matrix in the bus frame of reference i.e.

Y_F^{abc} is calculated by conducting short circuit test.

$$Y_F^{abc} = \frac{y_f}{2}\begin{bmatrix} 0 & 0 & 0 \\ 0 & +1 & -1 \\ 0 & -1 & +1 \end{bmatrix} \quad \text{where } y_f = \frac{1}{Z_f}$$

$$Y_F^{012} = \frac{y_f}{2}\begin{bmatrix} 0 & 0 & 0 \\ 0 & +1 & -1 \\ 0 & -1 & +1 \end{bmatrix}$$

From eq.(9), we get

$$\begin{bmatrix} I^0_{P(F)} \\ I^1_{P(F)} \\ I^2_{P(F)} \end{bmatrix} = \frac{y_f}{2}\begin{bmatrix} 0 & 0 & 0 \\ 0 & 1 & -1 \\ 0 & -1 & 1 \end{bmatrix}\begin{bmatrix} 1 & 0 & 0 \\ 0 & 1+Z^1_{PP}\frac{y_f}{2} & -Z^1_{PP}\frac{y_f}{2} \\ 0 & -Z^1_{PP}\frac{y_f}{2} & 1+Z^1_{PP}\frac{y_f}{2} \end{bmatrix}^{-1}\begin{bmatrix} 0 \\ \sqrt{3} \\ 0 \end{bmatrix}$$

$$\begin{bmatrix} E^0_{P(F)} \\ E^1_{P(F)} \\ E^2_{P(F)} \end{bmatrix} = \begin{bmatrix} 1 & 0 & 0 & 0 \\ 0 & 1+Z^1_{PP}\frac{y_f}{2} & -Z^1_{PP}\frac{y_f}{2} & \sqrt{3} \\ 0 & -Z^1_{PP}\frac{y_f}{2} & 1+Z^1_{PP}\frac{y_f}{2} & 0 \end{bmatrix}$$

and

$$\begin{bmatrix} E^0_{i(F)} \\ E^1_{i(F)} \\ E^2_{i(F)} \end{bmatrix} = \begin{bmatrix} 0 & Z^0_{iP} & 0 & 0 & I^0_{P(F)} \\ \sqrt{3} - 0 & & Z^1_{iP} & 0 & I^1_{P(F)} \\ 0 & 0 & 0 & Z^2_{iP} & I^2_{P(F)} \end{bmatrix}$$

$$\begin{bmatrix} i^0_{ij(F)} \\ i^1_{ij(F)} \\ i^2_{ij(F)} \end{bmatrix} = \begin{bmatrix} y^0_{ij,\beta\sigma} & 0 & 0 \\ 0 & y^1_{ij,\beta\sigma} & 0 \\ 0 & 0 & y^2_{ij,\beta\sigma} \end{bmatrix} \begin{bmatrix} (E^0_{\beta(F)} - E^0_{\sigma(F)}) \\ (E^1_{\beta(F)} - E^1_{\sigma(F)}) \\ (E^2_{\beta(F)} - E^2_{\sigma(F)}) \end{bmatrix}$$

From above equations it is clear, that, in this case only positive and negative sequence quantities are present.

3.2A.3 1-Ø to ground fault :

Consider fault in any phase 'a' through Z_f

$$Z_F^{ab} = Z_F^{bc} = Z_F^{ca} = 0$$

$$Z_F^{aa} = Z_f \quad Z_F^{bb} = Z_F^{cc} = \alpha, \quad \alpha \text{ being very high.}$$

$$Z_F^{abc} = \begin{bmatrix} Z_f & 0 & 0 \\ 0 & \alpha & 0 \\ 0 & 0 & \alpha \end{bmatrix} \; ; \; Y_F^{abc} = [Z_F^{abc}]^{-1} = \begin{bmatrix} y_f & 0 & 0 \\ 0 & 0 & 0 \\ 0 & 0 & 0 \end{bmatrix}$$

$$Y_F^{012} = \frac{y_f}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & 1 & 1 \\ 1 & 1 & 1 \end{bmatrix}$$

From eqn. (9), we have,

$$\begin{bmatrix} I^0_{P(F)} \\ I^1_{P(F)} \\ I^2_{P(F)} \end{bmatrix} = \frac{y_f}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & 1 & 1 \\ 1 & 1 & 1 \end{bmatrix} \begin{bmatrix} 1 + \frac{y_f}{3} Z^0_{PP} & \frac{y_f}{3} Z^0_{PP} & \frac{y_f}{3} Z^0_{PP} \\ \frac{y_f}{3} Z^1_{PP} & 1 + \frac{y_f}{3} Z^1_{PP} & \frac{y_f}{3} Z^1_{PP} \\ \frac{y_f}{3} Z^1_{PP} & \frac{y_f}{3} Z^1_{PP} & 1 + \frac{y_f}{3} Z^2_{PP} \end{bmatrix}^{-1} \begin{bmatrix} 0 \\ \sqrt{3} \\ 0 \end{bmatrix}$$

$$\begin{bmatrix} E^0_{P(F)} \\ E^1_{P(F)} \\ E^2_{P(F)} \end{bmatrix} = \begin{bmatrix} 1 + \frac{y_f}{3} Z^0_{PP} & \frac{y_f}{3} Z^0_{PP} & \frac{y_f}{3} Z^0_{PP} \\ \frac{y_f}{3} Z^1_{PP} & 1 + \frac{y_f}{3} Z^1_{PP} & \frac{y_f}{3} Z^1_{PP} \\ \frac{y_f}{3} Z^1_{PP} & \frac{y_f}{3} Z^1_{PP} & 1 + \frac{y_f}{3} Z^2_{PP} \end{bmatrix}^{-1} \begin{bmatrix} 0 \\ \sqrt{3} \\ 0 \end{bmatrix}$$

$$\begin{bmatrix} E^0_{i(F)} \\ E^1_{i(F)} \\ E^2_{i(F)} \end{bmatrix} = \begin{bmatrix} 0 \\ \sqrt{3} \\ 0 \end{bmatrix} - \begin{bmatrix} Z^0_{iP} & 0 & 0 \\ 0 & Z^1_{iP} & 0 \\ 0 & 0 & Z^1_{iP} \end{bmatrix} \begin{bmatrix} I^0_{P(F)} \\ I^1_{P(F)} \\ I^2_{P(F)} \end{bmatrix}$$

Direct short circuit i.e. Bolted Fault :

Here Z_f is zero i.e. Z_f and Y_f are undefined.

3.2B1. 1-Ø-G fault without any fault impedence :

Considering fault on phase a, the boundary conditions are,

$$E^{a}_{P(F)} = 0$$

$$I^{b}_{P(F)} = 0$$

$$I^{c}_{P(F)} = 0$$

Voltage at the faulted bus :

$$\begin{bmatrix} 0 \\ E^{b}_{P(F)} \\ E^{c}_{P(F)} \end{bmatrix} = \begin{bmatrix} 1 \\ \alpha^2 \\ \alpha \end{bmatrix} - \begin{bmatrix} Z_{11} & Z_{12} & Z_{13} \\ Z_{21} & Z_{22} & Z_{23} \\ Z_{31} & Z_{32} & Z_{33} \end{bmatrix} \begin{bmatrix} I^{a}_{P(F)} \\ 0 \\ 0 \end{bmatrix}$$

hence, we get : $1 = Z_{11}\, I^{a}_{P(F)}$

$$E^{b}_{P(F)} = \alpha^2 - Z_{21}\, I^{a}_{P(F)}$$

$$E^{c}_{P(F)} = \alpha - Z_{31}\, I^{a}_{P(F)}$$

here

$$Z_{11} = Z^{aa}_{PP}$$

$$Z_{12} = Z^{ab}_{PP} = Z_{21}$$

$$Z_{13} = Z^{ac}_{PP} = Z_{31}$$

Similarly voltages at the buses other than faulted one

$$E^{abc}_{i(F)} = E^{abc}_{i(0)} - [Z_{iP}] \; Z^{abc}_{P(F)} \quad \text{for } i = 1,2,3\ldots.n$$

$$i \neq P$$

3.2.B2. <u>Line-to-line fault</u> :

Consider L-L fault between two phases b and c without fault impedence. The boundary conditions are :

$$E^{b}_{P(F)} = E^{c}_{P(F)}$$

$$I^{b}_{P(F)} = I^{c}_{P(F)}$$

$$I^{a}_{P(F)} = 0$$

The faulted bus voltage is represented by the following equation

$$E^{-abc}_{P(F)} = E^{abc}_{P(0)} - [Z_{PP}) \; I^{abc}_{P(F)}$$

Substituting the boundary conditions, we have,

$$\begin{bmatrix} E^{a}_{P(F)} \\ E^{b}_{P(F)} \\ E^{b}_{p(F)} \end{bmatrix} = \begin{bmatrix} 1 \\ \alpha^2 \\ \alpha \end{bmatrix} - \begin{bmatrix} Z_{11} & Z_{12} & Z_{13} \\ Z_{21} & Z_{22} & Z_{23} \\ Z_{31} & Z_{32} & Z_{33} \end{bmatrix} \begin{bmatrix} 0 \\ I^{b}_{P(F)} \\ -I^{b}_{P(F)} \end{bmatrix}$$

where $Z_{11} = Z^{aa}_{PP}$

$$Z_{12} = Z^{ab}_{PP} = Z_{21}$$

$$Z_{13} = Z^{ac}_{PP} = Z_{31}$$

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Phase fault current is given by

$$\frac{E^b_{P(F)}}{E^b_{P(F)}} = \frac{\alpha^2 - Z_{22}\, I^b_{P(F)} + Z_{23}\, I^b_{P(F)}}{\alpha - Z_{32}\, I^b_{P(F)} + Z_{33}\, I^b_{P(F)}}$$

$$1 = \frac{\alpha^2 - (Z_{22} - Z_{23})\, I^b_{P(F)}}{\alpha - (Z_{32} - Z_{33})\, I^b_{P(F)}}$$

From above

$$I^b_{P(F)} = \frac{(\alpha^2 - \alpha)}{(Z_{22} - Z_{23}) - (Z_{32} - Z_{33})}$$

and

$$I^c_{P(F)} = -\frac{(\alpha^2 - \alpha)}{(Z_{22} - Z_{23}) - (Z_{32} - Z_{33})}$$

3.3 Case Study : Chukha Transmission System :

For the test system shown in Fig. 3.3 the following fault studies were carried out on DEC-1090 at I.I.T. Kanpur,

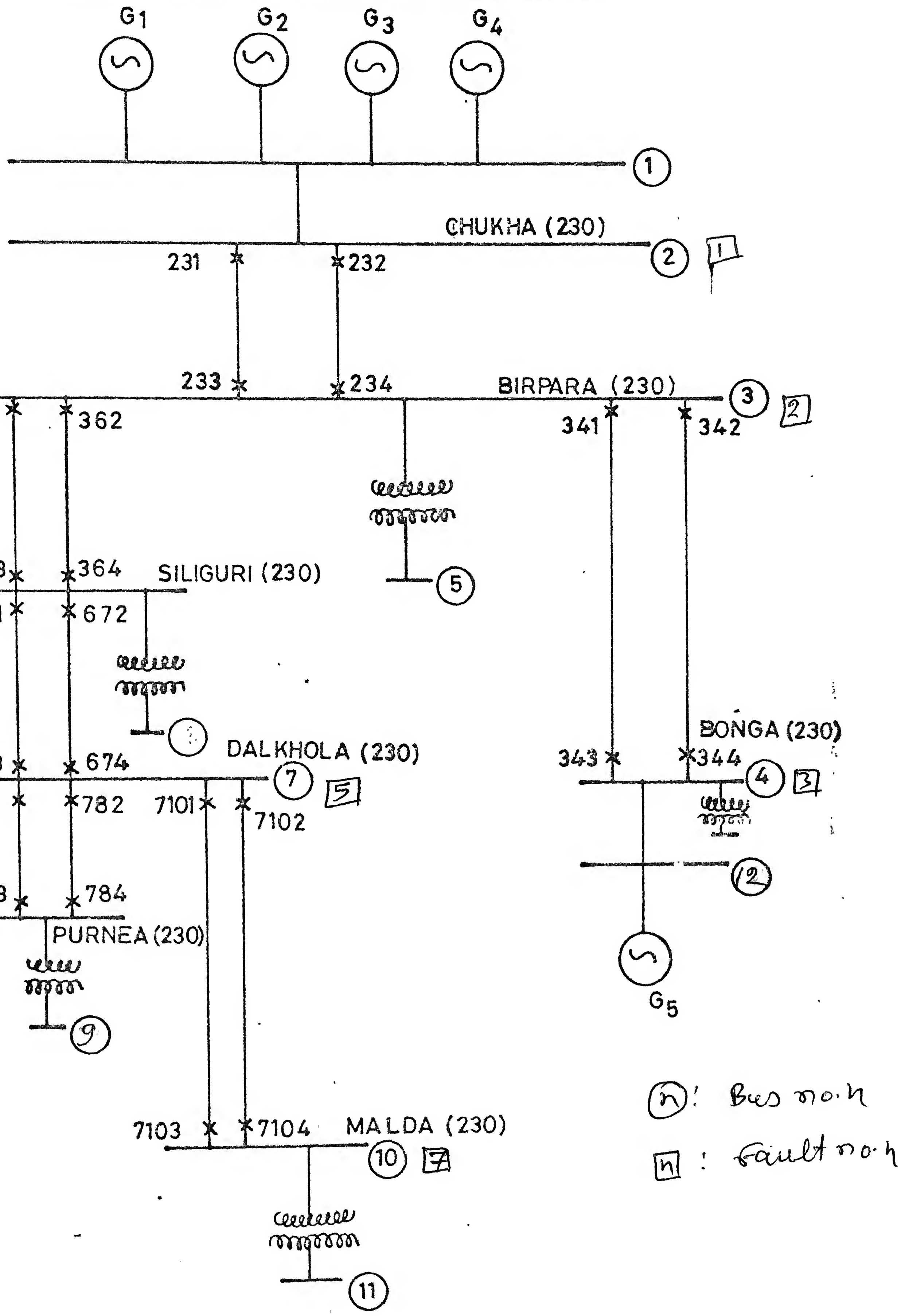
(1) Single-line to ground fault (without fault impedence)

(2) 3-phase to ground fault (without fault impedence)

(3) Line-to-line fault (without fault impedence).

All the above mentioned studies were carried out under the

CHUKHA TRANSMISSION SYSTEM



assumptions stated in article 3.2 with all the lines and generators intact. The results of these studies are shown in tables 1-7.

CHAPTER-4

RELAY SETTING AND CO-ORDINATION

4.1 Introductory Remarks :

The relay setting criterion depends upon the impedence seen upto the point of fault for distance relays and minimum and maximum current possible through each relay for over-current relays settings. In this chapter we have discussed in detail the settings as well as the factors affecting the settings and coordination both for distance and overcurrent relays.

4.2 Distance Relay Setting :

The fundamental concept concerning distance relay setting is as follows :

The operating zone for each relay element is defined accurately and setting coordination with relays in the forward adjacent stations is established. The optimum setting values are achieved through various load flow and fault analysis covering not only the basic system configuration but also all anticipated changes in system configuration which may influence the relay setting values.

Relay settings are determined using the fault voltages and currents by conducting several studies.

Shunt effects and fault resistances are also taken into account for the purpose.

Here, we have considered directional distance relays (i.e. Mho's relays) having 3-zones. The first zone is that of instantaneous operation for faults in the primary line. The other two zones protect the main line and adjacent lines with time delays increasing in discrete steps. For each relay, we must find impedence value for setting of each zone and time delay settings for zone-2 and zone-3 such that entire system is perfectly coordinated.

4.2.1 <u>Setting of First Zone</u> :

The first zone is that of instantaneous operation for faults on the primary line. It protects the primary line upto 80-90% of its length i.e. it never covers the remote bus.

The setting value for 1st zone is given as,

$$X_1 = K_1 Z_1$$

where X_1 : setting value of 1st zone

K_1 : 0.8 to 0.9 for phase relays

: 0.6 to 0.7 for ground relays

Z_1 : positive sequence impedence of the line to which it is connected.

In the caseof multi-terminal line, Z_1 should be equal to the minimum value of positive sequence impedences upto the next buses i.e. the remote buses.

In case any outfeeds or infeeds are present (particularly for distribution systems) then the Z-1 setting gets affected.

In case of infeeds : (see Fig. 4.2) apparent impedence seen is more than actual impedence of line by a factor $\frac{I_3}{I_2}(Z_{NF})$. Thus, any absence of infeed will stretch zone-1 reach even beyond the next bus which should be avoided. Because of this, the relay setting should be equal to 0.8 to 0.9 times impedence of smallest line length from each relaying point (in absence of infeed).

In case of outfeeds: (shown in Fig. 4.3) Here apparent impedence seen by relay is less than actual impedence of line. Thus it tends to overreach by a factor of $\frac{I_2}{I_1}(Z_{NF})$ in presence of outfeed. In this case, minimum apparent impedence seen upto the next buse with outfeeds present is used to set the Z-1 of relays.

4.2.2 Setting of Zone-2 :

The zone-2 protects the remaining part of the line left unprotected by Z-1 plus remote bus in all conditions and it is desirable to cover as much of the adjacent lines as possible (at least upto 20% of its length) to provide

back-up protection. It has a timer associated with it (T-2).

For back-up, the following considerations are taken into account (see Figs. 4.1, 4.2 and 4.3) :

Case (i) : If more than one line requires back-up protection from the same relay, then impedence tap setting of the relay for back-up operation is calculated as follows :

(a) Smallest of all the lines requiring back-up operation is considered and fault (3-Ø-G) is created at 50% length of the line. Then apparent impedence seen from relay location for back-up protection of this line is calculated say, it is Z_a.

(b) Longest of all lines requiring back-up protection is considered and fault (3-Ø-G) is created at 20% length of the line. Apparent impedence seen from relay location is calculated, say it is Z_b.

If $Z_a \geq Z_b$, then relay tap for back-up operation is set to Z_a, otherwise, any of the following two criterian may be adopted.

1. pilot relaying for smallest line or
2. changing of time-delay operation for back-up operation.

The choice of one from the above proposed two schemes depends on coordination criteria of the relay with the

POSSIBLE SYSTEM CONFIGURATIONS

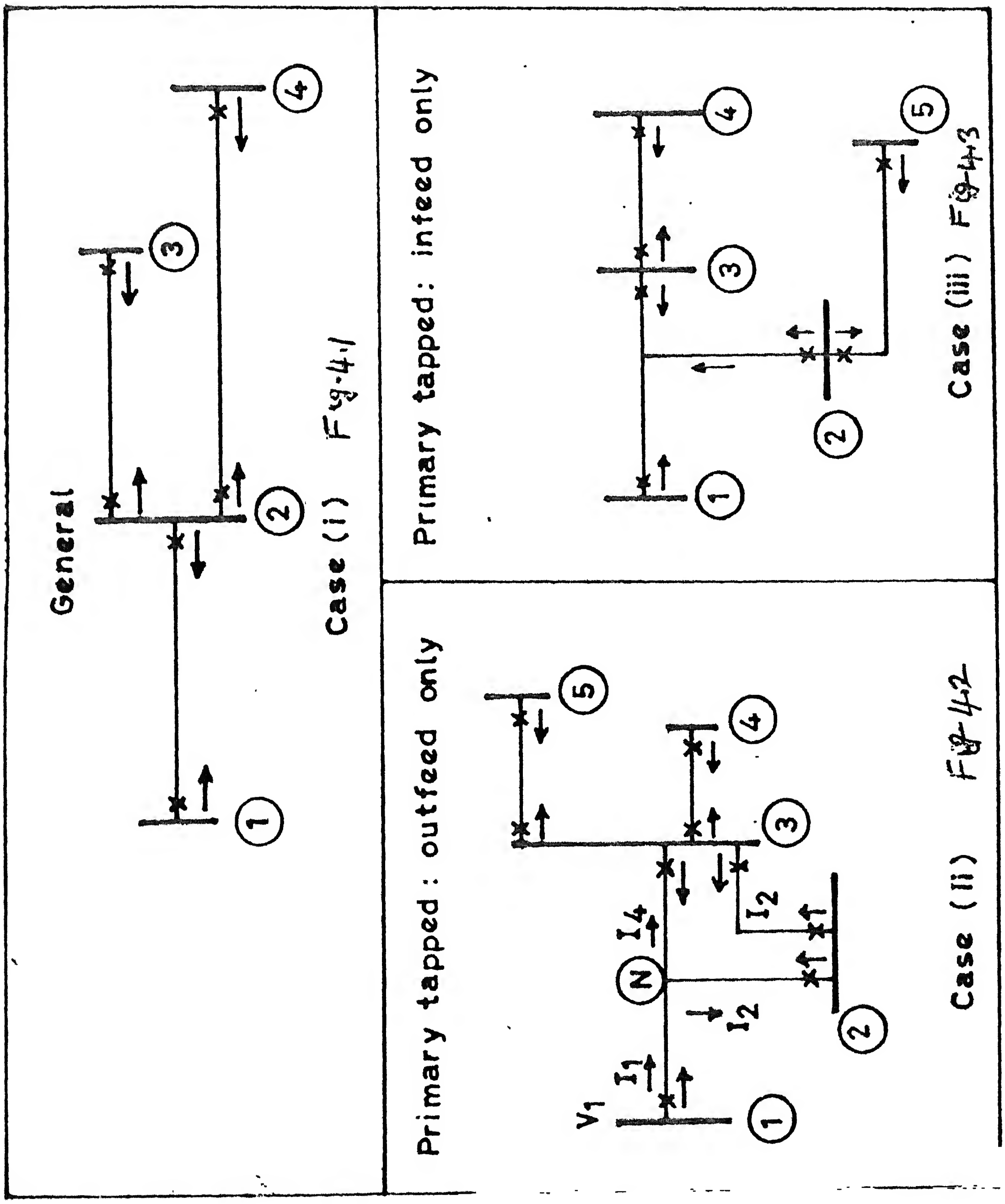


FIG. 4.1, 4.2, 4.3

others in the system. If (1) is choosen, then impedence tap setting for back-up operation is determined from the consideration of the remaining lines to be protected. If (2) is considered then it is to be ensured that this present value of time-delay is within the limit specified for time-delay operation of back-up.

Case (ii) : In this case with the outfeed present we proceed to determine impedence tap setting value for back-up operation as in case (i).

Case (iii) : In this impedence tap setting for back-up operation is determined by proceeding similarily as in case (i) with the infeeds not considered.

Case (ii) and case (iii) are usually the case with distribution systems.

It should be ensured that Z-2 does not operate for faults at next remote bus.

4.2.3 Setting of Z-3 :

The zone-3 of the distance relay is set to provide back-up protection to the main line as well as all the adjacent lines. It is also used to start the carriers. Thus, they are set to overreach the farthest remote bus. However, it is to be ensured that they do not operate under minimum loading conditions. The limiting load impedence

value of each relay is calculated first. The impedence setting should be more than minimum load impedence. Consider the typical Mho characteristics of a distance relay shown in Fig. 4.2.1 where

τ : relay set angle

θ_{li} : line impedence angle

$\theta_{le,mx}$: maximum load angle (representing worst loading condition)

$Z_{lo,mn}$: minimum load impedence

Z_s : impedence setting of the relay

Z_{li} : minimum load impedence expressed in line quantities.

It should be ensured that zone-3 should not exceed Z_{li};

$$Z_{li} = 0.9 \; Z_{lo,mn} \cdot \left[\frac{\cos(\tau - \theta_{li})}{\cos(\tau - \theta_{le,mx})}\right]$$

Zone-3 impedence setting is choosen to be smaller of

(1) Load impedence given by above equation,

(2) The maximum apparent impedence from the back-up relay to the farthest second remote bus.

In addition to consideration of load impedence, transient and dynamic power swings could also affect the zone-3 operation of distance relays.

The timer of Z-3 is set equal to timer setting value of Z-2 plus minimum coordination interval.

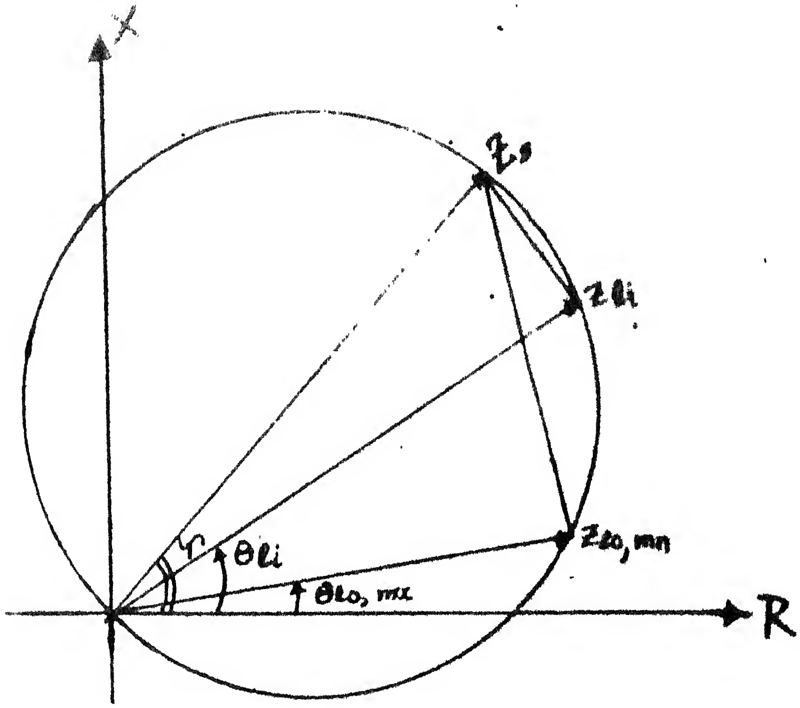


FIG: 4.2.1 Typical Mho characteristics

The algorithms to carryout the setting process for distance relays are presented here and results from the test system are summarised later.

4.2.4 Algorithm for Setting Calculation

Setting calculation method is shown in Fig. 4.4. For each relay location worst possible system configuration is determined through a subroutine called WORST. This subroutine determines the possible configuration of system which gives rise to minimum impedence seen from each relay location for a fault, if so happens, on the remote and next remote buses for primary and back-up operations of distance relays and for overcurrent relays setting, it determines the possible system configuration which gives rise to minimum and maximum fault current levels through each relay location.

The impedence so determined is called here, as 'worst impedence' for distance relay and 'maximum current' so determined is called worst current for o/c relay.

The maximum fault current is given by 3-L-G fault with maximum generation and minimum fault current is given by L-L fault with minimum generation. This result is useful for o/c relay settings.

The number of fault calculations to be carried out is also optimised by recognising the fact that for each

algorithm for calculating fault quantities under worst system configuration.

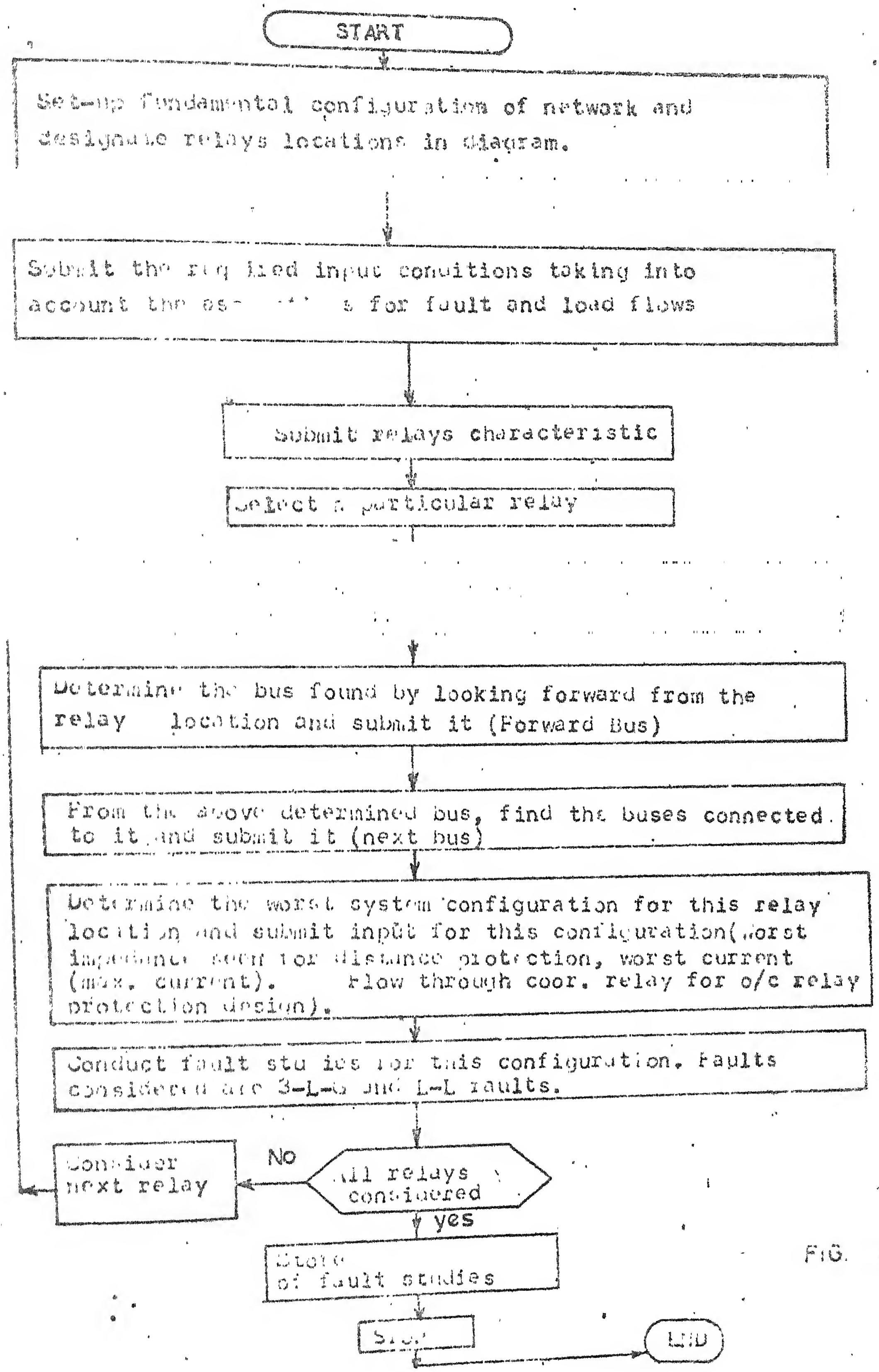
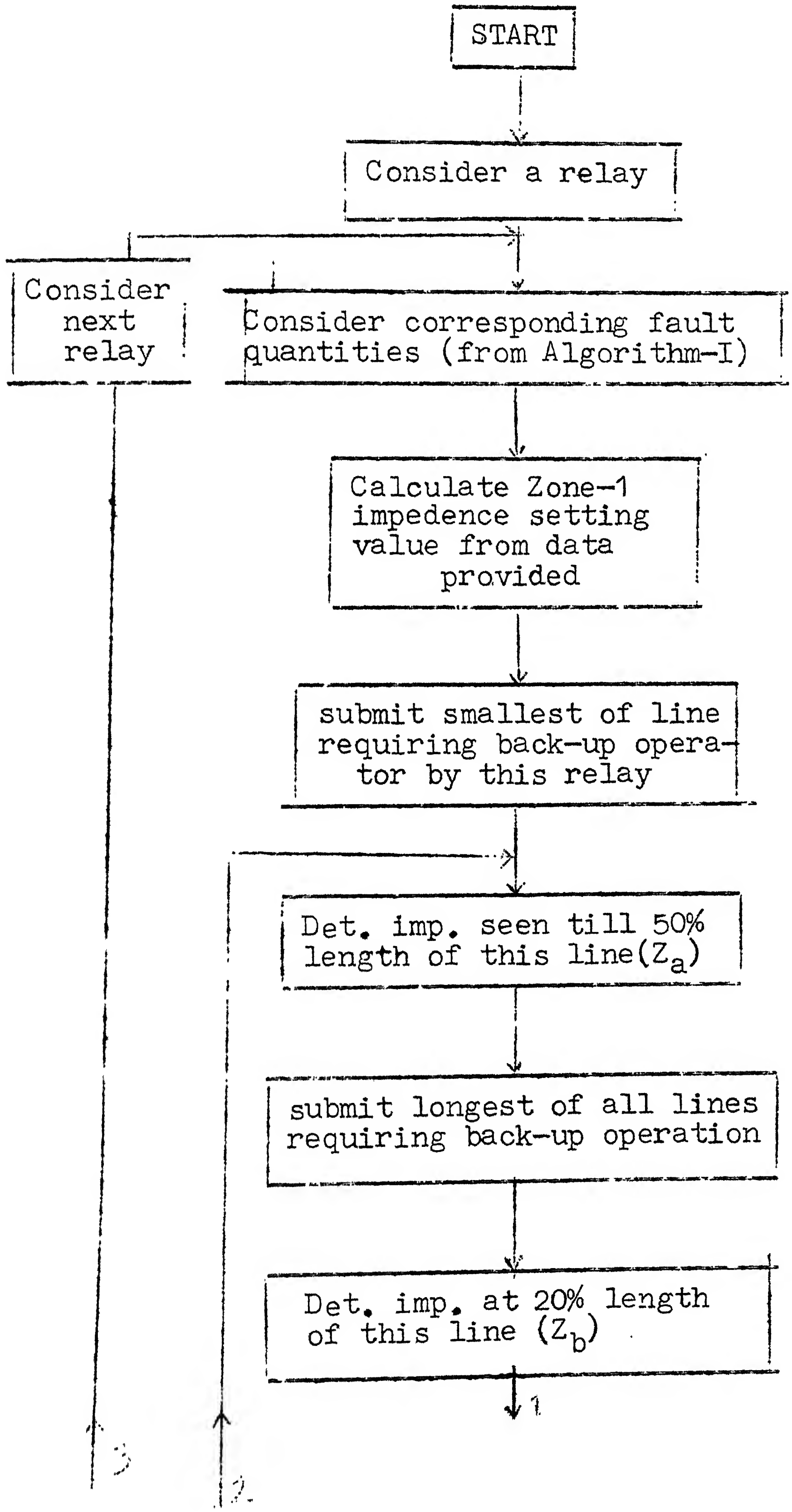


FIG. 4.4

Algorithm-II : Calculating Impedence Tap Setting



(Continued)

Algorithm-II (Continued)

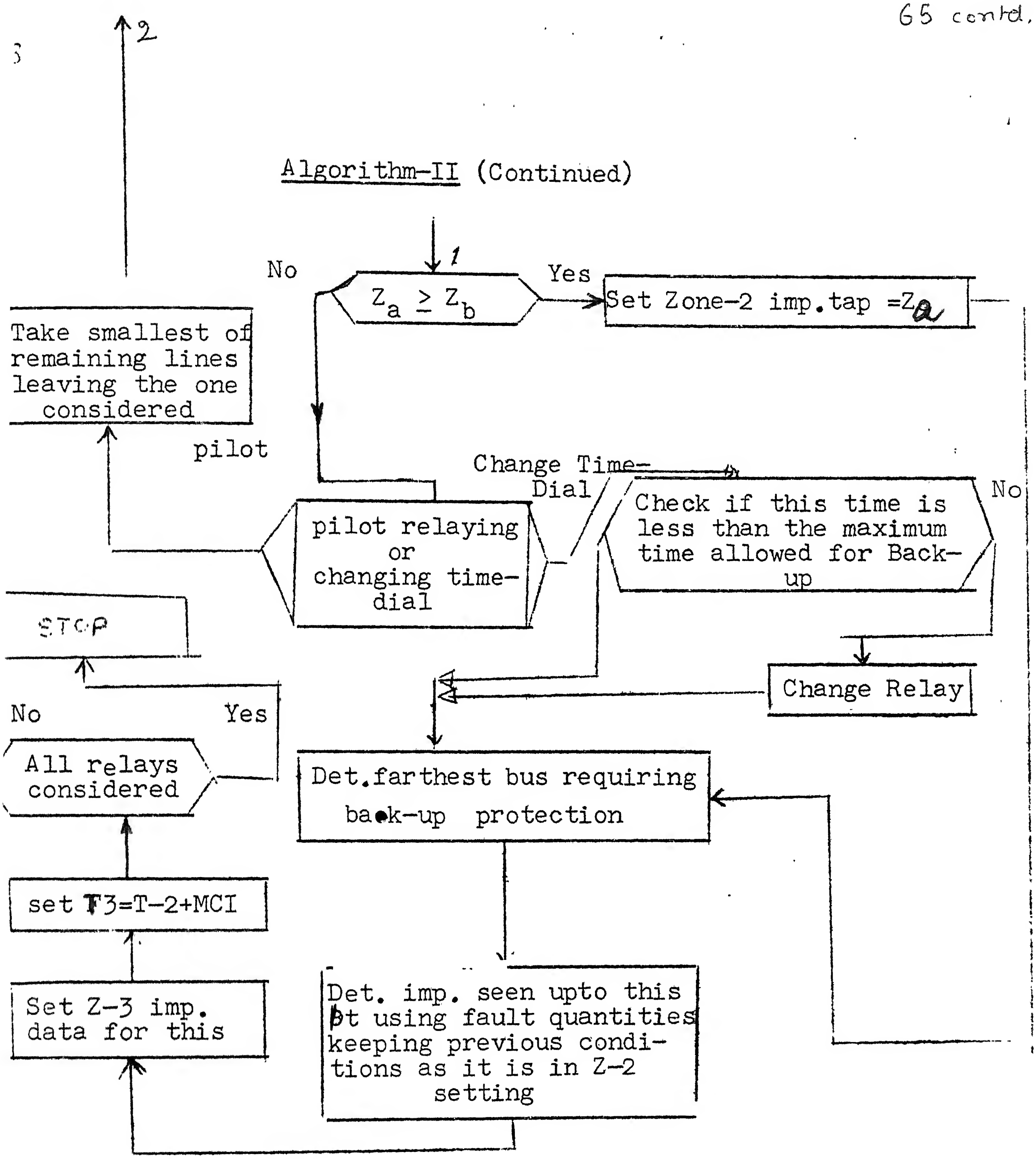


Fig. 4.5.

Instantaneous tap setting : It is specified in terms of maximum possible fault current times a factor 1.2 to 1.3. This maximum current is maximised over worst possible situation arising in the network for the relay to be set. The factor 1.2 to 1.3 is selected to avoid overreaching of the instantaneous operation range to minimise the interruption of power to consumers.

Pick-up tap setting : We first determine the allowable range and then allow the user to select within this range.

1 : The lower limit is determined by including the effect of overloading and power swing; and hence,

$$\text{lower limit} = F_P \times \text{Maximum load current through relay}$$

F_P : factor i.e. 1.20 - 1.30

If any relay tap corresponding to this value is not available, then minimum available tap on the relay can be used for this lower limit. At the same time, it should be ensured that minimum remote bus fault current (i.e. determined by conducting L-L fault with minimum generation) is picked up by this relay otherwise it has to be replaced.

The upper limit is smaller value of :

1) minimum remote bus fault current (i.e. L-L fault with minimum generation) times 0.5 to 0.6. This factor takes

relay operation the fault has to be considered only at remote bus and next remote bus. This reduces the number of fault calculations thus reducing the computer time for calculations.

Algorithm - I incorporates above mentioned conditions and calculates voltage and current levels for all relays . It is presented in Fig. 4.4.

Algorithm - II uses the datas generated by Algorithm-I for calculating the impedence tap settings of distance relays. It is presented in Fig. 4.5. The basis for determining the setting values are presented in article 4.2.1, 4.2.2 and 4.2.3.

The settings determined through these algorithms are presented in Table6later.

4.3 Overcurrent Relay Setting

The directional overcurrent relays (for phase fault) are assumed to have instantaneous time delay operation. Hence, three parameters for each relay are specified, namely, instantaneous setting, pick-up tap setting and time-dial setting.

Ideally, the relay should trip instantaneously for any fault on the primary line, i.e., on the line, the relay provides primary protection. However, it must not trip instantaneously for a fault on an adjacent line.

Algorithm-III for calculating settings of instantaneous and pack-up taps.

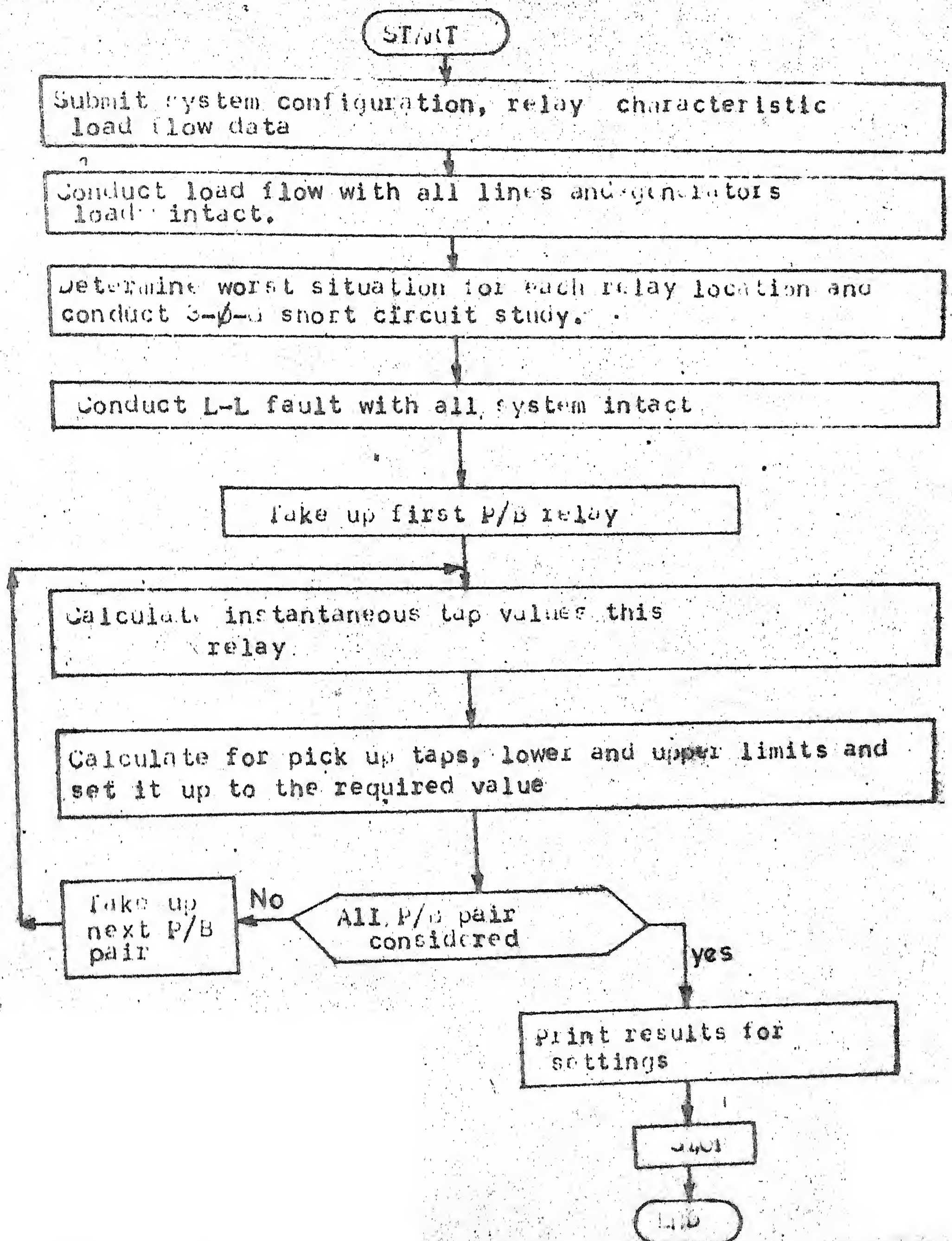


Fig. A.6: Flow chart for setting instantaneous and ps pick-up taps.

Algorithm-III for calculating settings of instantaneous and pack-up taps.

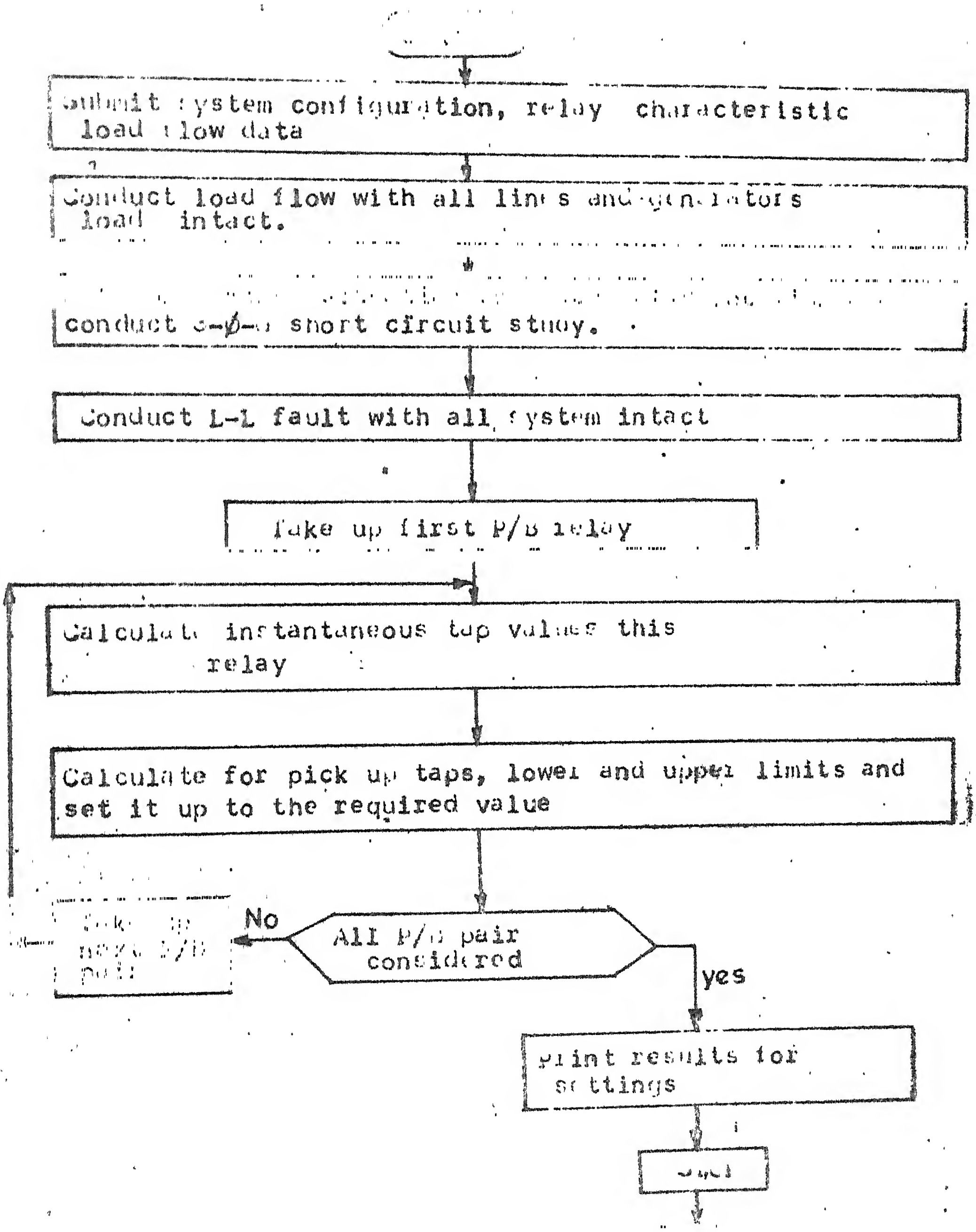


Fig. A.6: Flow chart for setting instantaneous and pick-up taps.

Note : (1) In three terminal lines, it may be that maximum current through relay location for instantaneous operation is much higher than the fault duty of the breaker. In such circumstances, one can override the setting criteria defined above.

(2) The pick-up setting with respect to a weak-fed terminal supplying a very low fault current for a remote bus fault may be unrealistically very low and creates problem of coordination. One can change the criteria by considering fault at 80 to 90% of line and obtaining resonable pick-up tap setting.

CHAPTER-5

RELAY CO-ORDINATION

5.1 Introduction :

The proper coordination of relays is essential to avoid the following problems to some extent :

(1) losing synchronism of system,

(2) unwanted interruption and wastage of power,

(3) interaction and maloperation among relays

(4) selectivity of relays.

A fully coordinated relaying scheme results in a minimum coordination time in the operation between each primary/ back-up relay pairs. Any change in the setting of one relay requires changes in the settings of adjacent relays to maintain proper coordination. This propagation of setting changes can cover a large portion of the network and can occur many times in the search of new settings. The coordination interval constraint involves multiple relays. Having repeatedly changed many relays without achieving satisfactory result, one thinks of the possibility of replacing the relays with the one having different threshold characteristics.

5.2 Coordination of Distance Relays :

A distance protection scheme comprising directional distance relays of Mho type with three zones of operation is considered. A fully coordinated result for distance relays should indicate the impedence setting values for all the three zones in terms of various impedence taps available on the relays and also the timer settings associated with second and third zone relays.

a) Z-2 timer setting (T-2) and coordination :

The coordination issue here is, that, the second zones of all primary/back-up (P/B) pairs either never interact or if they do, the time delay of back-up relay must exceed that of the primary relay by a coordination time interval (MCI). The Algorithm-IV for setting zone-2 timer is illustrated in Fig. 5.1 with flow chart showing coordination of distance relays.

The coordination is completed at the end of the first round of determing timer setting values if none of the relays have second zone delays greater than minimum coordination interval defined for distance relays. If any of the relay has an increased second zone time delay, we compute second time and modify the delay's accordingly to achieve system coordination.

h) Z-3 timer setting (T-3) and coordination :

The Z-3 timers of all the P/B pairs should coordinate among themselves.

The Z-3 timer (T-3) is set equal to T-2 plus minimum coordination interval. Each P/B pair is taken and checked for coordination, if it does not co-ordinate, then either Z-3 timer setting is modified or little coordination interval is sacrificed. If still it does not coordinate, then relay parameters are changed or it is replaced with another one.

The Algorithm-IV developed for Z-2 timer coordination can be used for Z-3 timer coordination determination with slight modification in algorithm.

5.3 Coordination of Overcurrent Relay :

The coordination of a system of overcurrent relays requires determination of three parameters normally associated with any kind of overcurrent relay, namely, the instantaneous pick-up tap value, the time-delay pick-up tap value and the time-dial setting value for all the relays in the system to satisfy the coordination criteria. The algorithm needed to carryout coordination process is presented here and results of test system is presented later.

5.3.1 Coordination algorithm :

The instantaneous tap settings and the pick-up tap settings are determined in previous chapter. The selection

Algorithm-IV

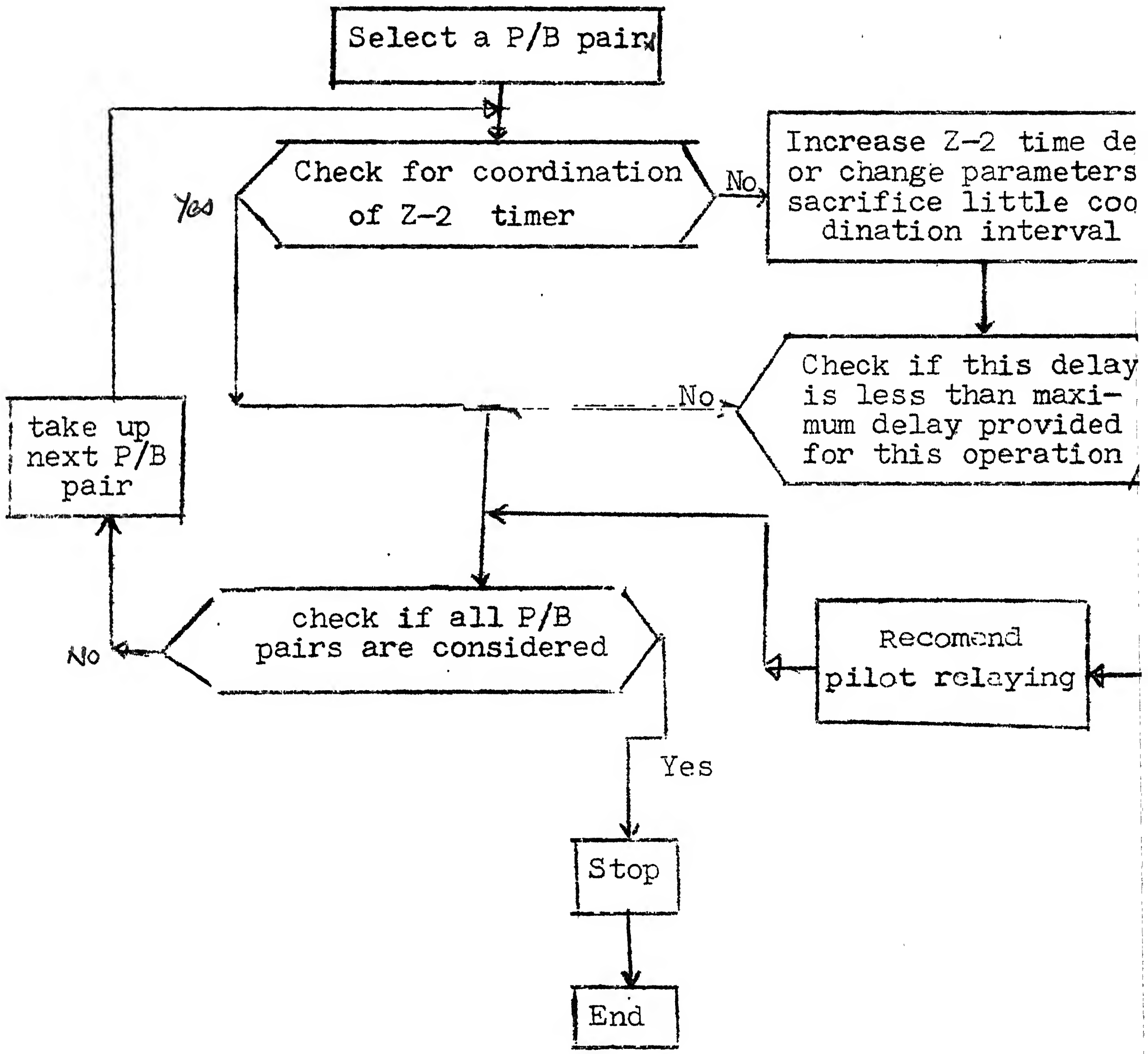


Fig. 5.1.

of the time dial setting is the most involved portion of the coordination process. Each primary/back-up relay in the system is checked for proper action for various types of faults that ffect the current through these relays. The faults considered are the ones which give minimum and maximum possible current through these relays.

All the relays in the system are assigned a time-dial value equal to the minimum tap value available on the relay. Then each back-up relay is set so that it coordinates with all its primary relays for all the fault current pairs fed as input.

The main criteria for the coordination of a given relay pair is that the operating time of a back-up relay should be at least equal to the operating time of the primary relay plus a minimum coordinating time interval (MCI). **Algorithm-V** detailing the steps involved in calculating the coordination process is shown in Fig.5.2.

The result obtain for coordination of distance and overcurrent relays are presented in the later chapter.

Algorithm-V

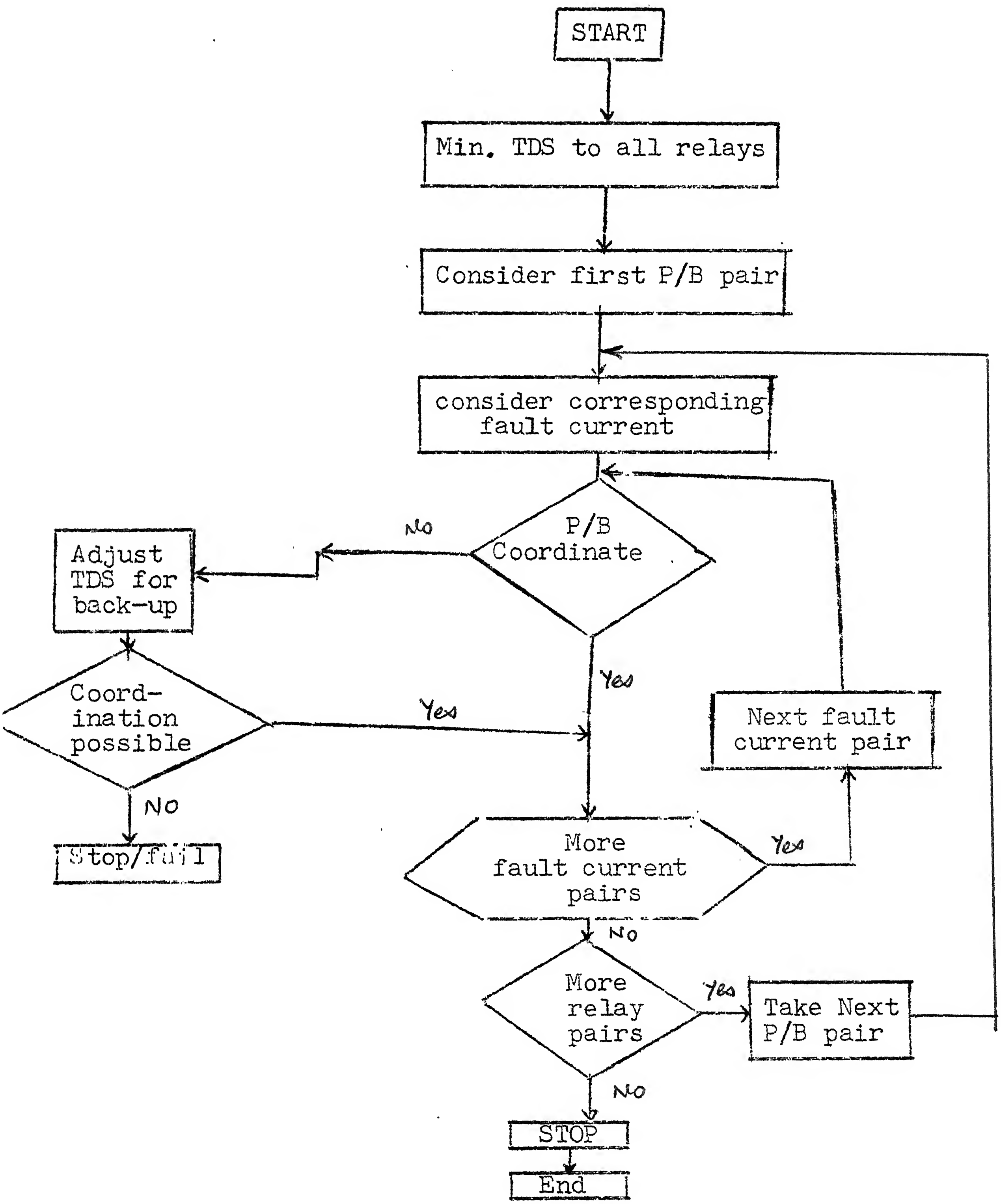


Fig. 5.2. Flow chart for overcurrent relay coordination.

CHPATER - 6

A CASE STUDY : CHUKHA TRANSMISSION SYSTEM

All the algorithms developed to determine the settings and coordination of both the distance and overcurrent relays have been tested on the sample system ''CHUKHA TRANSMISSION SYSTEM'' shown in Fig. 6.1. The line parameters are given in Table 1. Relay~~s~~ characteristics ~~is~~ are shown in Table 1A. Base MVA and base KV are taken to be 100 MVA and 230 KV respectively.

The three-phase-to-ground fault and single-phase-to-ground fault studies have been carried out with maximum generation and all lines intact using the algorithms developed in Chapter 3. The results of these studies are presented in Table 2 and 3.

Line-to-line fault with minimum generation possible and all lines intact in system have been conducted. The result of this study is presented in Table 4.

Algorithm-I generates the respective fault quantities required for relay setting and coordination. The fault quantities so determined correspond~~s~~ to the worst situation arising in the system for setting and coordinating distance and overcurrent relays. The relay location, type of fault and respective quantities for the purpose of relay setting~~s~~ are presented in Table 5.

CHUKHA TRANSMISSION SYSTEM

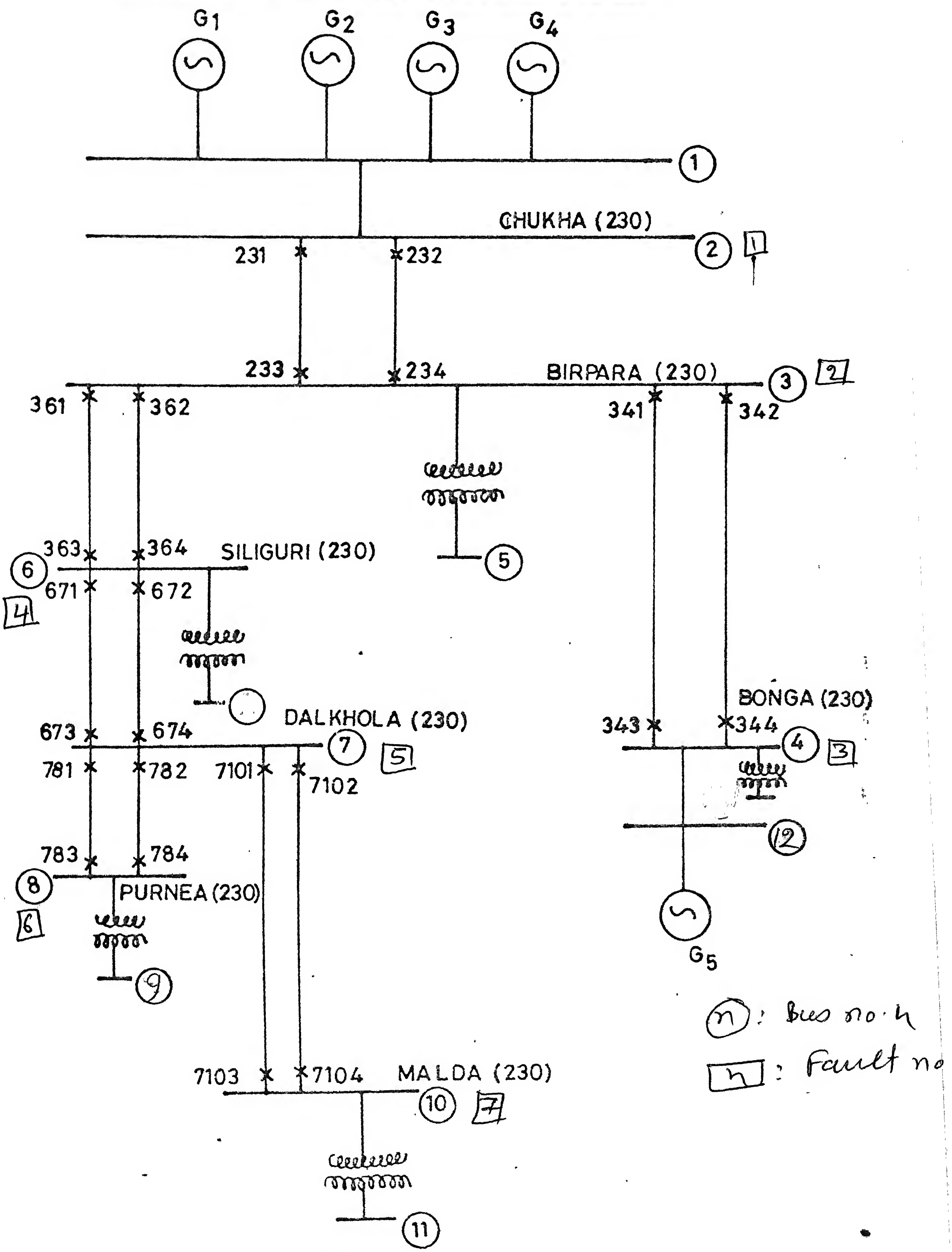


FIG. 5·1

Algorithm-II determines the distance relay (impedence) tap settings and Algorithm-IV determines the timer setting of the elements Z-2 and Z-3. The results of the various tap settings and timer setting of distance relays are presented in Table 6.

Algorithm-III determines the instantaneous and pick-up tap values and Algorithm-V, the time-dial setting of overcurrent relays. The result of the same is presented in Table 7.

TABLE -1

I N F E E D   F R O M   C H U K H A   A N D   B O N G A   O N L Y

LIST OF INPUT DATA

ES	NO OF LINES	REF BUS	SMLST BUS	NO OF FAULTS	PREFAULT VOLT IND	THREE PHASE BASE MVA
	13	13	1	7	0	100.0000

WITH CORRESPONDING BUS NUMBERS IN BRACKET

1) CHUKA220(2) BRPRA220(3) BONGA220(4) BRPRA132(5) SILGU220(6) DLKHO220(

9) MALDA220(10) MALDA132(11) BONGA11 (12) GROUND (13)

FAULTED BUS(NO)	PRINT OF FAULT	IMPEDANCE TO GROUND(ZG)		FAULT IMPEDANCE	
UKA220(2)	3-PHASE TO GROUND	0.0000	0.0000	0.0000	0.0000
PRA220(3)	3-PHASE TO GROUND	0.0000	0.0000	0.0000	0.0000
NGA220(4)	3-PHASE TO GROUND	0.0000	0.0000	0.0000	0.0000
LGU220(6)	3-PHASE TO GROUND	0.0000	0.0000	0.0000	0.0000
KHO220(7)	3-PHASE TO GROUND	0.0000	0.0000	0.0000	0.0000
RNE220(8)	3-PHASE TO GROUND	0.0000	0.0000	0.0000	0.0000
LDA220(10)	3-PHASE TO GROUND	0.0000	0.0000	0.0000	0.0000

LINE DATA

FROM BUS(NO)	TO BUS(NO)	ZERO SEQ.IMPEDANCE		POSITIVE SEQ,IMPEDANCE	
CHUKHA11(1)	GROUND (13)	0.0000	0.0214	0.0000	0.0348
CHUKHA11(1)	CHUKA220(2)	0.0000	0.0258	0.0000	0.0298
CHUKA220(2)	BRPRA220(3)	0.0365	0.1583	0.0061	0.0287
BRPRA220(3)	BONGA220(4)	0.0780	0.3390	0.0130	0.0630
BRPRA220(3)	BRPRA132(5)	0.0000	0.0850	0.0000	0.1000
BRPRA220(3)	SILGU220(6)	0.0421	0.1815	0.0070	0.0390
SILGU220(6)	DLKHO220(7)	0.0676	0.3050	0.0096	0.0471
DLKHO220(7)	PURNE220(8)	0.0466	0.2110	0.0066	0.0324
PURNE220(8)	PURNE132(9)	0.0000	0.0450	0.0000	0.0500
DLKHO220(7)	MALDA220(10)	0.0659	0.2985	0.0094	0.0459
MALDA220(10)	MALDA132(11)	0.0000	0.0850	0.0000	0.1000
BONGA220(4)	BONGA11 (12)	0.0000	0.0312	0.0000	0.0391
BONGA11 (12)	GROUND (13)	0.0000	0.0209	0.0000	0.0446

PREFAULT BUS VOLTAGES

TAGES ARE ASSUMED TO BE (1.,0.) PER UNIT WITH RESPECT TO THE REFERENCE BUS

TABLE - 1A

(RELAY CHARACTERISTICS)

Distance Relay			Overcurrent Relays	
Imp. Tap Range (ohm)	Z2 Timer Range (sec.)	Z3 Timer Range (sec.)	Inst. Tap Range (ohm)	Pick-up Tap Range (ohm)
5-25	0.1-1	0.3-3	0.1-0.5	0.5-1.5
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-

All relays are of same type.

CT ratio = 400

VT ratio = 1000

TABLE-2

(FAULT QUANTITIES 3-PH.-GROUND)

APPARENT IMPEDENCE AS SEEN FROM THE RELAY LOCATION AT

BUS NO. 2

FROM (2) TO (3)

FAULT NO	VOLT-A	VOLT-B	VOLT-C	CURR-A	CURR-B	CURR-C
1	0.0000	0.0000	0.0000	5.6679	5.6679	5.6579
2	0.3138	0.3138	0.3138	10.6956	10.6955	10.6956
3	0.5949	0.5949	0.5949	6.3509	6.3509	5.3509
4	0.5953	0.5953	0.5953	6.3265	6.3265	5.3265
5	0.7302	0.7302	0.7302	4.2291	4.2291	4.2291
6	0.7806	0.7805	0.7806	3.4431	3.4431	3.4431
7	0.7965	0.7965	0.7965	3.1954	3.1954	3.1954

BUS NO. 2

FAULT NO			
1	0.0000	0.0000	0.0000
2	0.0293	0.0293	0.0293
3	0.0937	0.0937	0.0937
4	0.0941	0.0941	0.0941
5	0.1727	0.1727	0.1727
6	0.2267	0.2257	0.2257
7	0.2493	0.2493	0.2493

BUS NO. 3

FROM (3) TO (4)

FAULT NO	VOLT-A	VOLT-B	VOLT-C	CURR-A	CURR-B	CURR-C
1	0.1663	0.1663	0.1663	5.6679	5.6679	5.6679
2	0.0000	0.0000	0.0000	6.7902	6.7902	5.7902
3	0.4085	0.4085	0.4085	6.3509	5.3509	5.3509
4	0.4098	0.4098	0.4098	4.0165	4.0165	4.0165
5	0.6062	0.6062	0.6062	2.6849	2.6849	2.6849
6	0.6796	0.6795	0.6796	2.1859	2.1859	2.1859
7	0.7028	0.7028	0.7028	2.0286	2.0285	2.0286

BUS NO. 3

FAULT NO			
1	0.0293	0.0293	0.0293
2	0.0000	0.0000	0.0000
3	0.0643	0.0643	0.0643
4	0.0395	0.0395	0.0396
5	0.0877	0.0877	0.0877
6	0.1207	0.1207	0.1207
7	0.1345	0.1345	0.1345

BUS NO. 4

FROM (3) TO (6)

FAULT NO	VOLT-A	VOLT-B	VOLT-C	CURR-A	CURR-B	CURR-C
1	0.5309	0.5309	0.6309	0.0000	0.0000	0.0000
2	0.4368	0.4368	0.4368	0.0000	0.0000	0.0000
3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	0.6681	0.6681	0.6681	10.3423	10.3423	10.3423
5	0.7789	0.7789	0.7789	6.9136	6.9135	6.9136
6	0.8202	0.8202	0.8202	5.6286	5.6285	5.6286
7	0.8332	0.8332	0.8332	5.2237	5.2237	5.2237

BUS NO. 4

FAULT NO			
1	0.0937	0.0937	0.0937
2	0.0643	0.0643	0.0643
3	0.0000	0.0000	0.0000
4	0.1663	0.1663	0.1663
5	0.2901	0.2901	0.2901
6	0.3752	0.3752	0.3752
7	0.4107	0.4107	0.4137

BUS NO. 6

FROM (6) TO (7)

FAULT NO	VOLT-A	VOLT-B	VOLT-C	CURR-A	CURR-B	CURR-C
1	0.1663	0.1563	0.1563	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	0.4085	0.4085	0.4085	0.0000	0.0000	0.0000
4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	0.3323	0.3323	0.3323	6.9136	6.9135	6.9136
6	0.4567	0.4567	0.4567	5.6286	5.6285	5.6286
7	0.4958	0.4958	0.4958	5.2237	5.2237	5.2237

BUS NO. 6

FAULT NO			
1	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.0000
3	0.0000	0.0000	0.0000
4	0.0000	0.0000	0.0000
5	0.0481	0.0481	0.0481
6	0.0811	0.0811	0.0811
7	0.0949	0.0949	0.0949

BUS NO. 7

FROM (7) TO (8)

FAULT NO	VOLT-A	VOLT-B	VOLT-C	CURR-A	CURR-B	CURR-C
1	0.1663	0.1663	0.1663	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	0.4085	0.4085	0.4085	0.0000	0.0000	0.0000
4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
6	0.1861	0.1861	0.1861	5.6286	5.6285	5.6286
7	0.2447	0.2447	0.2447	0.0000	0.0000	0.0000

FROM (7) TO (10)

FAULT NO	CURR-A	CURR-B	CURR-C
1	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.0000
3	0.0000	0.0000	0.0000
4	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000
6	0.0000	0.0000	0.0000
7	5.2237	5.2237	5.2237

BUS NO. 7

FAULT NO			
1	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.0000
3	0.0000	0.0000	0.0000
4	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000
6	0.0331	0.0331	0.0331
7	0.0469	0.0469	0.0469

Result Interpretation of 3-Ø-fault study

Voltages at each bus and currents through each line for all seven faults is given in Table - 2 containing first six columns. The impedence seen from each relay is calculated by taking voltage of the corresponding bus and current flowing through the line in which relay will be implemented.

Ex: For relay 341 : $\dfrac{\text{Voltage at Bus (3)}}{\text{Current from Bus(3) to Bus (4)}}$ [For fault at Bus(3)]

361 : $\dfrac{\text{Voltage at Bus (3)}}{\text{Current through Bus(3) to Bus (6)}}$ [For fault at Bus (4)]

TABLE – 3

FAULT QUANTITIES : 1-PHASE GROUND.

BUS NO. 2 — FROM (2) TO (3)

FAULT NO	VOLT-A	VOLT-B	VOLT-C	CURR-A	CURR-B	CURR-C
1	0.0000	0.9935	0.9861	4.4234	1.3640	1.3640
2	0.5662	0.9814	0.9880	7.4718	0.1733	0.4738
3	0.6915	0.9377	0.9568	4.9649	1.5712	1.6712
4	0.7895	0.9904	0.9946	3.6374	0.0845	0.0846
5	0.8828	0.9945	0.9971	2.0293	0.0472	0.0472
6	0.8983	0.9952	0.9975	1.7610	0.0410	0.0410
7	0.9182	0.9961	0.9980	1.4178	0.0330	0.0330

BUS NO. 3 — FROM (3) TO (4)

FAULT NO	VOLT-A	VOLT-B	VOLT-C	CURR-A	CURR-B	CURR-C
1	0.2054	0.9722	0.9733	4.4234	1.3640	1.3640
2	0.0000	1.1629	1.2214	4.4594	0.1733	0.4738
3	0.4735	0.9531	0.9612	4.9649	1.5712	1.6712
4	0.5140	1.0758	1.0970	2.1709	0.0845	0.0846
5	0.7290	1.0414	1.0511	1.2111	0.0472	0.0472
6	0.7649	1.0358	1.0439	1.0510	0.0410	0.0410
7	0.8107	1.0287	1.0349	0.8462	0.0330	0.0330

BUS NO. 4 — FROM (3) TO (6)

FAULT NO	VOLT-A	VOLT-B	VOLT-C	CURR-A	CURR-B	CURR-C
1	0.6512	0.9315	0.9508	0.0000	0.0000	0.0000
2	0.6754	0.9651	0.9802	0.0000	0.0000	0.0000
3	0.0000	0.9853	0.9715	0.0000	0.0000	0.0000
4	0.8428	0.9813	0.9911	5.8079	0.0000	0.0000
5	0.9125	0.9895	0.9952	3.2403	0.0000	0.0000
6	0.9241	0.9902	0.9959	2.8118	0.0000	0.0000
7	0.9389	0.9927	0.9967	2.2639	0.0000	0.0000

BUS NO. 6 — FROM (5) TO (7)

FAULT NO	VOLT-A	VOLT-B	VOLT-C	CURR-A	CURR-B	CURR-C
1	0.2054	0.9722	0.9733	0.0000	0.0000	0.0000
2	0.0000	1.1629	1.2214	0.0000	0.0000	0.0000
3	0.4735	0.9531	0.9612	0.0000	0.0000	0.0000
4	0.0000	1.2559	1.2998	0.0000	0.0000	0.0000
5	0.4423	1.1322	1.1531	3.2403	0.0000	0.0000
6	0.5161	1.1132	1.1306	2.8118	0.0000	0.0000
7	0.6104	1.0892	1.1026	2.2639	0.0000	0.0000

BUS NO. 7 — FROM (7) TO (8)

FAULT NO	VOLT-A	VOLT-B	VOLT-C	CURR-A	CURR-B	CURR-C
1	0.2054	0.9722	0.9733	0.0000	0.0000	0.0000
2	0.0000	1.1629	1.2214	0.0000	0.0000	0.0000
3	0.4735	0.9531	0.9612	0.0000	0.0000	0.0000
4	0.0000	1.2559	1.2998	0.0000	0.0000	0.0000
5	0.0000	1.3331	1.3614	0.0000	0.0000	0.0000
6	0.1322	1.2822	1.3360	2.8118	0.0000	0.0000
7	0.3014	1.2197	1.2379	0.0000	0.0000	0.0000

FROM (7) TO (10)

CURR-A	CURR-B	CURR-C
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
0.0000	0.0000	0.0000
2.2639	0.0000	0.0000

APPARENT IMPEDENCE AS SEEN FROM THE RELAY LOCATION AT DIFFERENT BUSES

BUS NO. 2

FAULT NO.			
1	0.0000	0.7231	0.7229
2	0.0753	5.5451	5.6931
3	0.1393	0.5511	1.3725
4	0.2171	11.7022	11.7523
5	0.4350	21.0525	21.1150
6	0.5131	21.2990	21.1334
7	0.6475	33.1955	33.2331

BUS NO. 3

FAULT NO.			
1	0.0464	0.7123	0.7135
2	0.0000	5.5932	7.0259
3	0.0954	0.5703	0.5751
4	0.0885	0.0000	0.0000
5	0.2250	0.0000	0.0000
6	0.2720	0.0000	0.0000
7	0.3580	0.0000	0.0000

BUS NO. 4

FAULT NO.			
1	0.1472	0.6829	0.6971
2	0.1515	5.5513	5.6383
3	0.0000	5.5895	5.5813
4	0.3882	11.5012	11.7134
5	0.7534	20.3585	21.0771
6	0.8792	21.1847	21.3348
7	1.1095	30.0905	30.2126

BUS NO. 6

FAULT NO.			
1	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.0000
3	0.0000	0.0000	0.0000
4	0.0000	0.0000	0.0000
5	0.1365	0.0000	0.0000
6	0.1835	0.0000	0.0000
7	0.2695	0.0000	0.0000

BUS NO. 7

FAULT NO.			
1	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.0000
3	0.0000	0.0000	0.0000
4	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000
6	0.0473	0.0000	0.0000
7	0.1331	0.0000	0.0000

Result Interpretation of 1-Ø-fault study

Voltages at each bus and currents through each line for all seven faults is given in Table - 3 containing first six columns. The impedence seen from each relay is calculated by taking voltage of the corresponding bus and current flowing through the line in which relay will be implemented.

Ex : For relay 341 : $\dfrac{\text{Voltage at Bus (3)}}{\text{Current through Bus(3) to Bus(4)}}$ [For fault at Bus(3)]

361 : $\dfrac{\text{Voltage at Bus(3)}}{\text{Current hrough Bus (3) to Bus(6)}}$ [For fault at Bus(4)

LINE TO LINE FAULT QUANTITIES.

FAULT AT BUS NO = 1

SL NO.	VOLPA	VOLTPB	VOLPC	CURPA	CURPB	CURPC
1	[1.0000]	[.5000]	[0.5000]	[.0000]	9.1226]	[9.1226
1	[1.0000]	[.5000]	[0.5000]	[.0000]	2.9639]	[2.9639
2	[1.0000]	[.5641]	[0.6569]	[.0000]	2.9639]	[2.9639]
2	[1.0000]	[.5641]	[0.6569]	[.0000]	2.9656]	[2.9656]
3	[1.0000]	[.6267]	[0.7053]	[.0000]	2.9656]	[2.9656]
3	[1.0000]	[.6267]	[0.7053]	[.0000]	3.0508]	[3.0508]
4	[1.0000]	[.8163]	[0.7676]	[.0000]	3.0508]	[3.0508]
3	[1.0000]	[.6267]	[0.7053]	[.0000]	0.0918]	[0.0918]
5	[1.0000]	[.6238]	[0.7043]	[.0000]	0.0918]	[0.0918]
4	[1.0000]	[.8163]	[0.7676]	[.0000]	3.0499]	[3.0499]
9	[1.0000]	[.8977]	[0.8745]	[.0000]	3.0499]	[3.0499]
5	[1.0000]	[.6238]	[0.7043]	[.0000]	0.0174]	[0.0174]
6	[1.0000]	[.6245]	[0.7047]	[.0000]	0.0174]	[0.0174]
6	[1.0000]	[.6245]	[0.7047]	[.0000]	0.0000]	[0.0000]
7	[1.0000]	[.6245]	[0.7047]	[.0000]	0.0000]	[0.0000]
6	[1.0000]	[.6245]	[0.7047]	[.0000]	0.0000]	[0.0000]
8	[1.0000]	[.6245]	[0.7047]	[.0000]	0.0000]	[0.0000]

FAULT AT BUS NO = 3

SL NO.	VOLPA	VOLTPB	VOLPC	CURPA	CURPB	CURPC
4	[1.0000]	[.5000]	[0.5000	[.0000	8.8902]	8.8902]
1	[1.0000]	[.6772]	[0.6645	[.0000	2.9970]	2.9970]
2	[1.0000]	[.5247]	[0.4912	[.0000	2.9970]	2.9970]
2	[1.0000]	[.5247]	[0.4912	[.0000	2.9969]	2.9969]
3	[1.0000]	[.5000]	[0.5000	[.0000	2.9969]	2.9969]
3	[1.0000]	[.5000]	[0.5000	[.0000]	6.1350]	6.1350]
4	[1.0000]	[.7388]	[0.5180	[.0000]	6.1350]	6.1350]
3	[1.0000]	[.5000]	[0.5000	[.0000]	0.1844]	0.1844]
5	[1.0000]	[.4985]	[0.5016	[.0000]	0.1844]	0.1844]
4	[1.0000]	[.7388]	[0.5180	[.0000]	6.1356]	6.1356]
9	[1.0000]	[.8320]	[0.7377	[.0000]	6.1356]	6.1356]
5	[1.0000]	[.4985]	[0.5016	[.0000]	0.0357]	0.0357]
6	[1.0000]	[.4985]	[0.5016	[.0000]	0.0357]	0.0357]
6	[1.0000]	[.4985]	[0.5016	[.0000]	0.0000]	0.0000]
7	[1.0000]	[.4985]	[0.5016	[.0000]	0.0000]	0.0000]
6	[1.0000]	[.4985]	[0.5016	[.0000]	0.0000]	0.0000]
8	[1.0000]	[.4985]	[0.5016	[.0000]	0.0000]	0.0000]

FAULT AT BUS NO = 2

SL NO.	VOLPA	VOLTPB	VOLPC	CURPA	CURPB	CURPC
2	[1.0000]	[.5000]	[0.5000	[.0000]	[8.2016]	[8.2016
1	[1.0000]	[.6392]	[0.6392	[.0000]	[3.3403]	[3.3403
2	[1.0000]	[.5000]	[0.5000	[.0000]	[3.3403]	[3.3403
2	[1.0000]	[.5000]	[0.5000	[.0000]	[4.9329]	[4.9329
3	[1.0000]	[.5131]	[0.5305	[.0000]	[4.9329]	[4.9329
3	[1.0000]	[.5131]	[0.5305	[.0000]	[5.0774]	[5.0774
4	[1.0000]	[.7607]	[0.5996	[.0000]	[5.0774]	[5.0774
3	[1.0000]	[.5131]	[0.5305	[.0000]	[0.1511]	[0.1511
5	[1.0000]	[.5103]	[0.5305	[.0000]	[0.1511]	[0.1511
4	[1.0000]	[.7607]	[0.5996	[.0000]	[5.0793]	[5.0793
9	[1.0000]	[.8546]	[0.7833	[.0000]	[5.0793]	[5.0793
5	[1.0000]	[.5103]	[0.5305	[.0000]	[0.0293]	[0.0293
6	[1.0000]	[.5107]	[0.5309	[.0000]	[0.0293]	[0.0293
6	[1.0000]	[.5107]	[0.5309	[.0000]	[0.0000]	[0.0000
7	[1.0000]	[.5107]	[0.5309	[.0000]	[0.0000]	[0.0000
6	[1.0000]	[.5107]	[0.5309	[.0000]	[0.0000]	[0.0000
8	[1.0000]	[.5107]	[0.5309	[.0000]	[0.0000]	[0.0000

FAULT AT BUS NO = 4

SL NO.	VOLPA	VOLTPB	VOLPC	CURPA	CURPB	CURPC
3	[1.0000]	[.5000]	[0.5000	[.0000	[12.7111]	12.7111
1	[1.0000]	[.7473]	[0.6863	[.0000	[2.5430]	2.5430
2	[1.0000]	[.6185]	[0.4695	[.0000	[2.5430]	2.5430
2	[1.0000]	[.6185]	[0.4695	[.0000	[2.5427]	2.5427
3	[1.0000]	[.5900]	[0.4466	[.0000	[2.5427]	2.5427
3	[1.0000]	[.5900]	[0.4466	[.0000	[2.3863]	2.3863
4	[1.0000]	[.5000]	[0.5000	[.0000	[2.3863]	2.3863
3	[1.0000]	[.5900]	[0.4466	[.0000	[0.1523]	0.1523
5	[1.0000]	[.5881]	[0.4457	[.0000	[0.1523]	0.1523
4	[1.0000]	[.5000]	[0.5000	[.0000	[10.3419]	10.3419
9	[1.0000]	[.6430]	[0.6442	[.0000	[10.3419]	10.3419
5	[1.0000]	[.5881]	[0.4457	[.0000]	[0.0291]	0.0291
6	[1.0000]	[.5882]	[0.4463	[.0000]	[0.0291]	0.0291
6	[1.0000]	[.5882]	[0.4463	[.0000]	[0.0000]	0.0000
7	[1.0000]	[.5882]	[0.4463	[.0000]	[0.0000]	0.0000
6	[1.0000]	[.5882]	[0.4463	[.0000]	[0.0000]	0.0000
8	[1.0000]	[.5882]	[0.4463	[.0000]	[0.0000]	0.0000

5	[1.0000]	[.5000]	0.5000	[.0000]	5.4738	6.4738]
1	[1.0000]	[.8156]	0.7440	[.0000]	2.1975	2.1975]
2	[1.0000]	[.6789]	0.5683	[.0000]	2.1975	2.1975]
2	[1.0000]	[.6789]	0.5683	[.0000]	2.1994	2.1994]
3	[1.0000]	[.6412]	0.5480	[.0000]	2.1994	2.1994]
3	[1.0000]	[.6412]	0.5480	[.0000]	4.5006	4.5006]
4	[1.0000]	[.8313]	0.6410	[.0000]	4.5006	4.5006]
3	[1.0000]	[.6412]	0.5480	[.0000]	6.6492	6.6492]
5	[1.0000]	[.5497]	0.5000	[.0000]	6.6492	6.6492]
4	[1.0000]	[.8313]	0.6410	[.0000]	4.4989	4.4989]
9	[1.0000]	[.9035]	0.8066	[.0000]	4.4989	4.4989]
5	[1.0000]	[.5497]	0.5000	[.0000]	0.0342	0.0342]
6	[1.0000]	[.5000]	0.5000	[.0000]	0.0342	0.0342]
6	[1.0000]	[.5000]	0.5000	[.0000]	0.0000	0.0000]
7	[1.0000]	[.5000]	0.5000	[.0000]	0.0000	0.0000]
6	[1.0000]	[.5000]	0.5000	[.0000]	0.0000	0.0000]
8	[1.0000]	[.5000]	0.5000	[.0000]	0.0000	0.0000]

FAULT AT BUS NO. = 6

6	[1.0000]	[.5000]	0.5000	[.0000]	4.7723]	4.7723]
1	[1.0000]	[.7650]	0.8082	[.0000]	1.6167]	1.6167]
2	[1.0000]	[.6288]	0.6625	[.0000]	1.6167]	1.6167]
2	[1.0000]	[.6288]	0.6625	[.0000]	1.6178]	1.6178]
3	[1.0000]	[.5954]	0.6379	[.0000]	1.6178]	1.6178]
3	[1.0000]	[.5954]	0.6379	[.0000]	3.3107]	3.3107]
4	[1.0000]	[.4973]	0.7342	[.0000]	3.3107]	3.3107]
3	[1.0000]	[.5954]	0.6379	[.0000]	4.8932]	4.8932]
5	[1.0000]	[.5930]	0.5500	[.0000]	4.8932]	4.8932]
4	[1.0000]	[.4973]	0.7342	[.0000]	3.3103]	3.3103]
9	[1.0000]	[.5000]	0.8574	[.0000]	3.3103]	3.3103]
5	[1.0000]	[.5930]	0.5500	[.0000	4.7363]	4.7363
6	[1.0000]	[.5935]	0.5000	[.0000	4.7363]	4.7363
6	[1.0000]	[.5935]	0.5000	[.0000	0.0000]	0.0000
7	[1.0000]	[.5935]	0.5000	[.0000	0.0000]	0.0000
6	[1.0000]	[.5935]	0.5000	[.0000	0.0000]	0.0000
8	[1.0000]	[.5935]	0.5000	[.0000	0.0000]	0.0000

					CURPA	CURPB	CURPC
7	[1.0000]	[.5000]	0.5000	[.0000]	2.6301	2.6301]
1	[1.0000]	[.8908]	0.8976	[.0000]	0.8910	0.8910]
2	[1.0000]	[.8015]	0.8155	[.0000]	0.8910	0.8910]
2	[1.0000]	[.8015]	0.8155	[.0000]	0.8916	0.8916]
3	[1.0000]	[.7766]	0.7997	[.0000]	0.8916	0.8916]
3	[1.0000]	[.7766]	0.7997	[.0000]	1.8246]	1.8246]
4	[1.0000]	[.8915]	0.8563	[.0000]	1.8246]	1.8246]
3	[1.0000]	[.7766]	0.7997	[.0000]	2.6968]	2.6968]
5	[1.0000]	[.7002]	0.7371	[.0000]	2.6968]	2.6968]
4	[1.0000]	[.8915]	0.8563	[.0000]	1.8244]	1.8244]
9	[1.0000]	[.9406]	0.9230	[.0000]	1.8244]	1.8244]
5	[1.0000]	[.7002]	0.7371	[.0000]	2.6103]	2.6103]
6	[1.0000]	[.6062]	0.6629	[.0000]	2.6103]	2.6103]
6	[1.0000]	[.6062]	0.6629	[.0000]	2.6301]	2.6301]
7	[1.0000]	[.5000]	0.5000	[.0000]	2.6301]	2.6301]
6	[1.0000]	[.6062]	0.6629	[.0000]	0.0000]	0.0000]
8	[1.0000]	[.6062]	0.6629	[.0000]	0.0000]	0.0000]

FAULT AT BUS NO = 8

8	[1.0000]	[.5000]	0.5000	[.0000	3.1502	3.1502]
1	[1.0000]	[.8762]	0.8713	[.0000	1.0672	1.0672]
2	[1.0000]	[.7781]	0.7678	[.0000	1.0672	1.0672]
2	[1.0000]	[.7781]	0.7678	[.0000	1.0679	1.0679]
3	[1.0000]	[.7503]	0.7475	[.0000	1.0679	1.0679]
3	[1.0000]	[.7503]	0.7475	[.0000	2.1854	2.1854]
4	[1.0000]	[.8829]	0.8235	[.0000	2.1854	2.1854]
3	[1.0000]	[.7503]	0.7475	[.0000	3.2301	3.2301]
5	[1.0000]	[.6702]	0.6690	[.0000	3.2301	3.2301]
4	[1.0000]	[.8829]	0.8235	[.0000	2.1852	2.1852]
9	[1.0000]	[.9349]	0.9056	[.0000	2.1852	2.1852]
5	[1.0000]	[.6702]	0.6690	[.0000	3.1265	3.1265]
6	[1.0000]	[.5813]	0.5791	[.0000	3.1265	3.1265]
6	[1.0000]	[.5813]	0.5791	[.0000	0.0000	0.0000]
7	[1.0000]	[.5813]	0.5791	[.0000	0.0000	0.0000]
6	[1.0000]	[.5813]	0.5791	[.0000	3.1502	3.1502]
8	[1.0000]	[.5000]	0.5000	[.0000	3.1502	3.1502]

TABLE - 5

FAULT QUANTITIES GENERATED BY ALGO. I

Relay Location	Faulted BUS No.	Circuit out	Voltage at relay location	Current throu relay locati
231	3	No	0.5949	6.3509
231	4	No	0.5953	6.3265
231	6	No	0.7580	3.7959
343	2	No	0.5309	5.6679
343	3	No	0.4368	6.7902
343	6	No	0.7789	2.6849
361	6	No	0.6467	6.2054
361	7	No	0.7028	5.2237
671	7	No	0.3323	6.9136
671	8	No	0.4009	6.2054
671	10	No	0.4958	5.2237
781	8	No	0.1026	6.2054
781	10	No	0.2447	5.2237
7101	10	No	0.1026	5.2237
231	3	3(1 ckt. out)	0.4786	8.1563
231	4	,,	0.6588	5.3561
231	6	,,	0.6730	5.1268
343	2	,,	0.5981	4.8628
343	3	,,	0.4368	6.7902
343	6	,,	0.7571	2.9421
361	6	,,	0.3445	9.3947
361	7	,,	0.3722	5.8505
671	7	,,	0.3113	6.4761
671	8	,,	0.3779	5.8505
671	10	,,	0.4719	4.9698
781	8	,,	0.0967	5.8505
781	10	,,	0.2328	4.9698
7101	10	,,	0.2328	4.9698
231	3	3/4 (1 ckt. out)	0.4786	8.1563
231	4	,,	0.7466	3.9854
231	6	,,	0.7558	3.8323
343	2	,,	0.6943	3.7063
343	3	,,	0.6089	4.7326
343	6	,,	0.8171	2.2237
361	6	,,	0.3382	8.5360
361	7	,,	0.5310	6.0556
671	7	,,	0.2911	6.0556
671	8	,,	0.3556	5.5051
671	10	,,	0.4479	4.7183
781	8	,,	0.0910	5.5051
781	10	,,	0.2218	4.7183
7101	10	,,	0.2328	4.9698
231	3	7 (1 ckt. out)	0.4786	8.1563
231	4	,,	0.7466	3.9854
231	6	,,	0.7558	3.8323
343	2	,,	0.6943	3.7063
343	6	,,	0.6089	4.7326
361	6	,,	0.8171	2.2237
361	7	,,	0.4098	10.3423
671	7	,,	0.7043	5.1960
671	8	,,	0.4985	5.1960
671	10	,,	0.5382	4.7853
781	8	,,	0.5962	4.1794
781	10	,,	0.0781	4.7853
7101	10	,,	0.1958	4.1793
			0.1958	4.1743

TABLE - 6

DISTANCE RELAY SETTING FOR CHUKHA TRANSMISSION SYSTEM
(Infeed from Chukha and Bonga)

Relay No.	End	Settings						
		Z1	Z2		Z3		Offset Mho	
		Imp. (ohm)	Imp. (ohm)	Time (sec)	Imp. (ohm)	Time (sec)	Imp. (ohm)	Time (sec)
231	Chukha(2)	9.38	32.0	0.3	51.0	0.6	66.0	0.75
232	,,	9.38	32.0	0.3	51.0	0.6	66.0	0.75
233	BRPR(3)	9.38	17.58	0.3	23.43	0.6	30.46	0.75
234	,,	9.38	17.58	0.3	23.43	0.6	30.46	0.75
341	BRPR(3)	20.0	37.0	0.3	50.0	0.6	65.0	0.75
342	,,	20.0	37.0	0.3	50.0	0.6	65.0	0.75
343	BONGA(4)	20.0	30.86	0.3	45.0	0.6	58.5	0.75
344	,,	20.0	30.86	0.3	45.0	0.6	58.5	0.75
361	BRPR(3)	10.74	38.19	0.3	50.0	0.6	65.0	0.75
362	,,	10.74	38.19	0.3	50.0	0.6	65.0	0.75
363	SILR(6)	10.74	19.28	0.3	38.43	0.6	50.0	0.75
364	,,	10.74	19.28	0.3	38.43	0.6	50.0	0.75
671	SILR(6)	14.89	24.0	0.3	36.84	0.6	47.71	0.75
672	,,	14.89	24.0	0.3	36.84	0.6	47.71	0.75
781	DALKH(7)	5.12	6.4	0.3	7.0	0.6	9.1	0.75
782	PURN(8)	5.12	15.34	0.3	24.28	0.6	31.56	0.75
7101	DALKH(7)	14.51	18.14	0.3	19.00	0.6	24.7	0.75
7102	MALDA(10)	14.51	21.34	0.3	36.74	0.6	47.8	0.75

TABLE - 7

PHASE OVERCURRENT RELAY SETTING FOR CHUKHA TRANSMISSION SYSTEM

Relay No.	C/T Ratio	Inst. Setting Tap	Pick-up Tap	Time Dial Setting
231	400	6.57	0.67	0.5
232	400	6.57	0.67	0.5
233	400	3.909	0.5	0.5
234	400	3.909	0.5	0.5
341	400	3.442	0.5	0.5
342	400	3.442	0.5	0.5
344	400	3.85	0.5	0.5
343	400	3.85	0.5	0.5
361	400	6.43	0.68	0.5
362	400	6.43	0.68	0.5
363	-	-	-	-
671	400	4.33	0.5	0.5
672	400	4.33	0.5	0.5
673	-	-	-	-
674	-	-	-	-
781	400	4.70	0.5	0.5
782	400	4.70	0.5	0.5
783	-	-	-	-
784	-	-	-	-
7101	400	3.49	0.5	0.5
7102	400	3.49	0.5	0.5
7103	-	-	-	-

Minimum Tap (pick-up) available = 0.5
Minimum Time-Dial Setting = 0.5
VT Ratio = 1000.

All these algorithms have been tested on CHUKHA TRANSMISSION SYSTEM for which the data have been provided by NHPC. These algorithms have performed very satisfactorily, yielding results generally superior to those achieved manually with enormous decrease in time requirement. Consideration of recognising in advance of fault studies, the worst possible system configuration for determining the setting values of distance and overcurrent relays results in better setting values of relay which minimises the relay maloperation and also reduces the computer time for fault calculations.

The next section elaborates on what work would naturally follow the present work.

FUTURE SCOPE OF WORK

For distance relay zone-3 settings, the transient and dynamic power swing could be taken into account as they affect its operation. If the maximum value of such swings are available from a stability study, zone-3 can be set accordingly to be insensitive to these swings.

Graph theoretic approach could be applied to reduce the number of times one has to go through setting the relays if any second-zone setting of distance relays is changed.

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Graph theoretic approach could be applied to reduce the number of times one has to go through setting the relays if any second-zone setting of distance relays is changed.

A software can be developed to implement man-machine dialogue. This must provide for user control, the display of results and the status report that are requested.

As system size grows, data handling becomes difficult and, hence, some data management technique could be used in large power systems. Data management software permits a utility to limit the ability to modify data items.

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